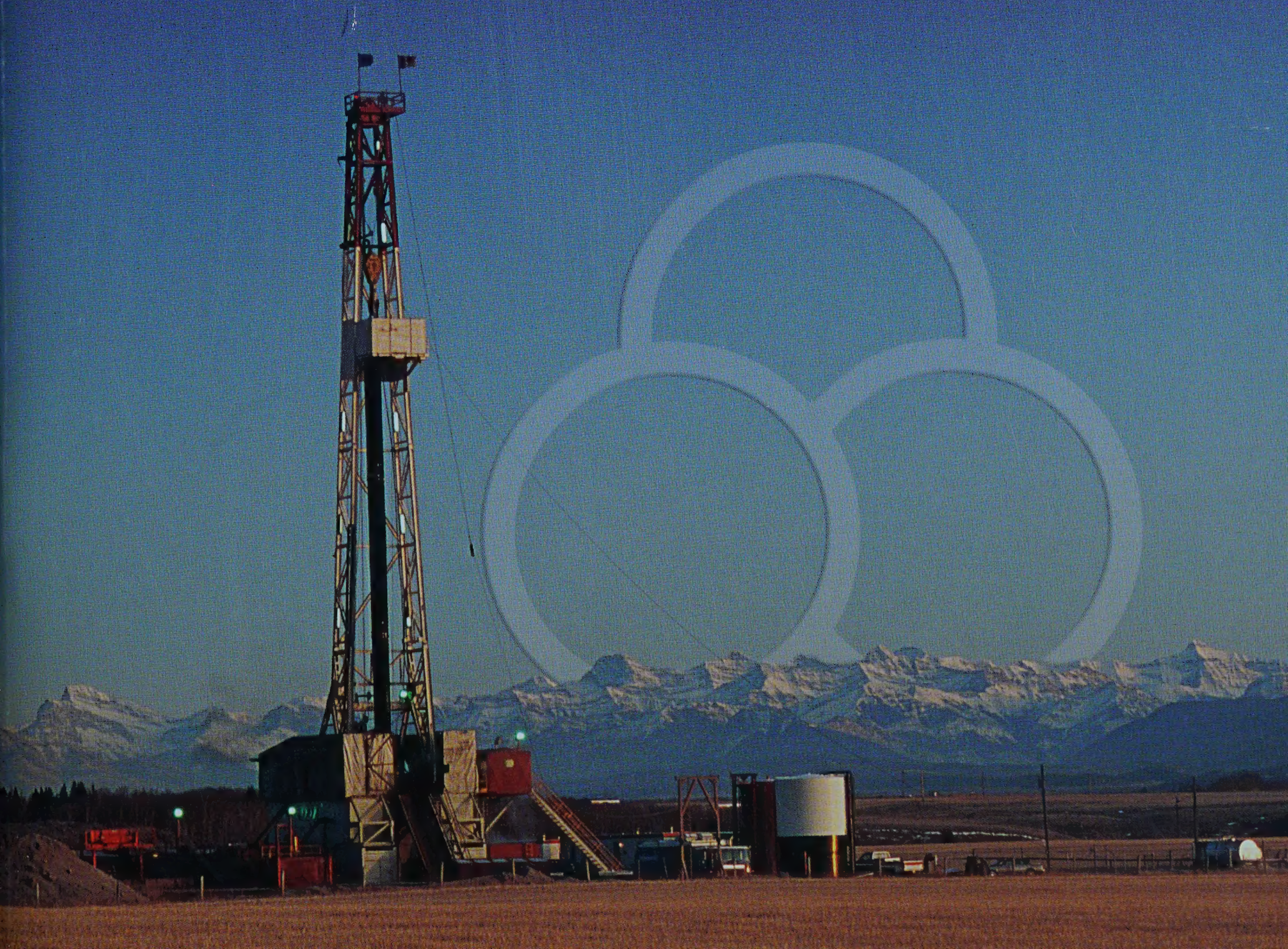
TriQuest Energy Corp.

2002 Annual Report



Corporate Profile

TriQuest Energy Corp. is a Calgary-based, junior resource company engaged in the exploration, development and production of natural gas and oil. Incorporated in 1996 as Corker Resources Inc., a new management team was put in place in May of 1999, the name was changed in July of 1999 to TriQuest Energy Corp., and the Company began to focus on generating drilling prospects and building a land base in west-central Alberta. In January of 2002, TriQuest acquired Sommer Energy Ltd., adding northeast Alberta as a core area, and adding two more skilled professionals to the management team. Further management changes were made in September 2002 and the share capital was restructured with a one for four-share consolidation.

In November 2002, the common shares of TriQuest commenced trading on the Toronto Stock Exchange, under the symbol "TRI". As at April 23, 2003 the Company had 19,615,843 shares issued and outstanding, and had granted 1,591,111 options to its key employees, consultants, and to its directors.

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Annual Meeting

The Annual General Meeting of Shareholders will be held on Wednesday, June 18, 2003 at 10:00 A.M. in the Cardium Room of the Calgary Petroleum Club, 319 - 5th Avenue S.W., Calgary, Alberta. All Shareholders are encouraged to attend.

Message *to the* Shareholders

TriQuest is pleased to present its financial and operating results for 2002. It was a record business year as the Company achieved substantial gains.

Highlights

During 2002 TriQuest:

- Completed the acquisition of Sommer Energy Ltd in January 2002 adding a major new shallow gas exploration and production area
- Participated in 75 (54.6 net) wells with an average of 73% working interest as compared to 65 (19.7 net) wells with an average working interest of 30% in 2001
- Tripled production, maintaining our strong natural gas focus (95%), to 1,434 boed from 467 boed
- More than doubled gross revenues and cash flow, despite a 15 % drop in product prices
- Tripled capital expenditures to $32.1 million including the acquisition of Sommer Energy
- Increased its Established Reserves base (before production) by 2,727 mboe (16.3 bcfe) at a finding and development cost of $10.76/boe ($1.79/mcfe). The reserves replacement ratio for 2002 was 5.2 times 2002 production
- Listed its shares on the Toronto Stock Exchange after completing a one for four share consolidation and then raised $8 million to fund its growing exploration program
- Increased its credit facility to $ 10 million from $ 3.5 million
- Increased its undeveloped land base by 145% to 145,800 net acres with an average 53% working interest

Strategy

TriQuest continues to concentrate its growth efforts on well-defined, natural gas prone core areas within the province of Alberta. Each of TriQuest's core areas fits into one of two categories. Firstly, TriQuest invests approximately 75-80% of its capital in core areas that are prone to shallow, lower risk, natural gas. Secondly, TriQuest invests approximately 20-25% of its capital in deeper drilling, higher risk, multi-zone prospects within its defined core areas that have the potential to provide our shareholders the opportunity to receive significant value growth and returns on their investment.

Operational results

TriQuest demonstrated exceptional operational gains in 2002 over 2001. Year over year production volumes increased threefold to 1,434 boed with a 95% weighting towards natural gas compared to 467 boed and 77% gas weighting in 2001. This demonstrates the Company's success at focusing on natural gas production.

Before production, the Company added approximately 2,717 mboe (16.3 bcfe) of Established Reserves. Total Established Reserves after production at December 31, 2002 were 4,616 mboe (27.70 bcfe) compared to 2,431 mboe (14.59 bcfe) last year. TriQuest's finding and development costs were $10.76 per boe, or $1.79 per mcfe on an established basis. TriQuest replaced its 2002 production by 5.2 times in 2002.

TriQuest drilled a record 75 (54.6 net) wells during 2002, resulting in 56 (38 net) gas wells, 2 (1.2 net) oil wells, and 17 (15.2) were abandoned. During the first quarter of 2003, the Company assumed operatorship of its drilling and pipelining program in the Tweedie/Wappau area in northeastern Alberta. As a result, TriQuest operated all but one of the 38 (28.5 net) wells drilled during the first quarter of 2003.

Financial Returns and Capital Investment

Gross revenues increased 161% to $12.6 million from $4.8 million. Cash flow from operations increased 115% to $5.4 million from $2.5 million. During the fourth quarter of 2002, gross revenues were $5.1 million and cash flow was $3.0 million demonstrating the positive effect of stronger natural gas prices and increased production volumes.

During 2002, TriQuest made $32.1 million in capital expenditures, which included the acquisition of Sommer Energy Ltd. in January 2002 for a consideration of $12.5 million paid for by the issuance of 6.9 million common shares. The acquisition of Sommer Energy included the acquisition of cash in the amount of $4.5 million, working capital in the amount of $1.9 million and a future tax liability in the amount of $2.9 million. TriQuest funded the balance of its 2002 capital program from cash flow, an $ 8 million equity financing and its bank line of $ 10 million.

Excluding the acquisition of Sommer Energy Ltd., details of capital expenditures are as follows:

Land and property acquisitions	$ 3.2 million
Drilling and completion costs	$ 12.7 million
Equipment, facilities and tie-in costs	$ 6.4 million
Geological and Geophysical costs	$ 0.7 million
Office furniture and equipment	$ 0.1 million
Total	**$ 23.1 million**

At year-end 2002, Triquest had 19.5 million shares outstanding, no debt, positive working capital in the amount of $0.2 million and deductions available against future taxable income of $27.4 million.

Outlook for 2003

TriQuest continues to invest aggressively in its natural gas prone core areas and has set a capital budget of $23 million for 2003. The budget will fund the drilling of up to 110 wells and will be financed from cash flow and our credit facility. The budget was set assuming natural gas prices of $5.88 /mcf and US$ 24.50 per barrel of WTI crude oil.

TriQuest will continue to focus on the generation, capture and exploitation of natural gas opportunities in Alberta. TriQuest has demonstrated its ability to grow using the process of full cycle prospect generation through to production. TriQuest continues to believe that the best returns for our shareholders can be achieved through the drill bit.

Long term pricing for natural gas is very strong and a shortage of supply is currently driving pricing fundamentals. TriQuest's technical team and staff have enabled the Company to achieve record results for 2002. TriQuest looks forward to sustained growth through 2003 by continuing to emphasize natural gas exploration, development and production in Alberta.

On behalf of the Board of Directors

Bruce G. McIntyre
President and Chief Executive Officer
April 23, 2003

Review *of* Operations

Corporate Objectives

TriQuest's key objective is to generate superior growth in operating and financial performance which will generate increasing value for our shareholders. Our strategic business plan focuses on the efficient discovery, development and production of natural gas reserves in Alberta.

Internal prospect generation is a fundamental platform for enhancing the Company's long-term profitability and represents the greatest potential for low-cost reserve additions. The experienced team of professionals at TriQuest concentrates seventy-five percent of its energy and capital on low-to-medium risk natural gas plays. The TriQuest team compliments this with several high impact medium-to-high risk drilling opportunities to expose our shareholders to accelerated growth.

TriQuest takes advantage of its extensive technical experience and disciplined operational focus in three Alberta core project areas:

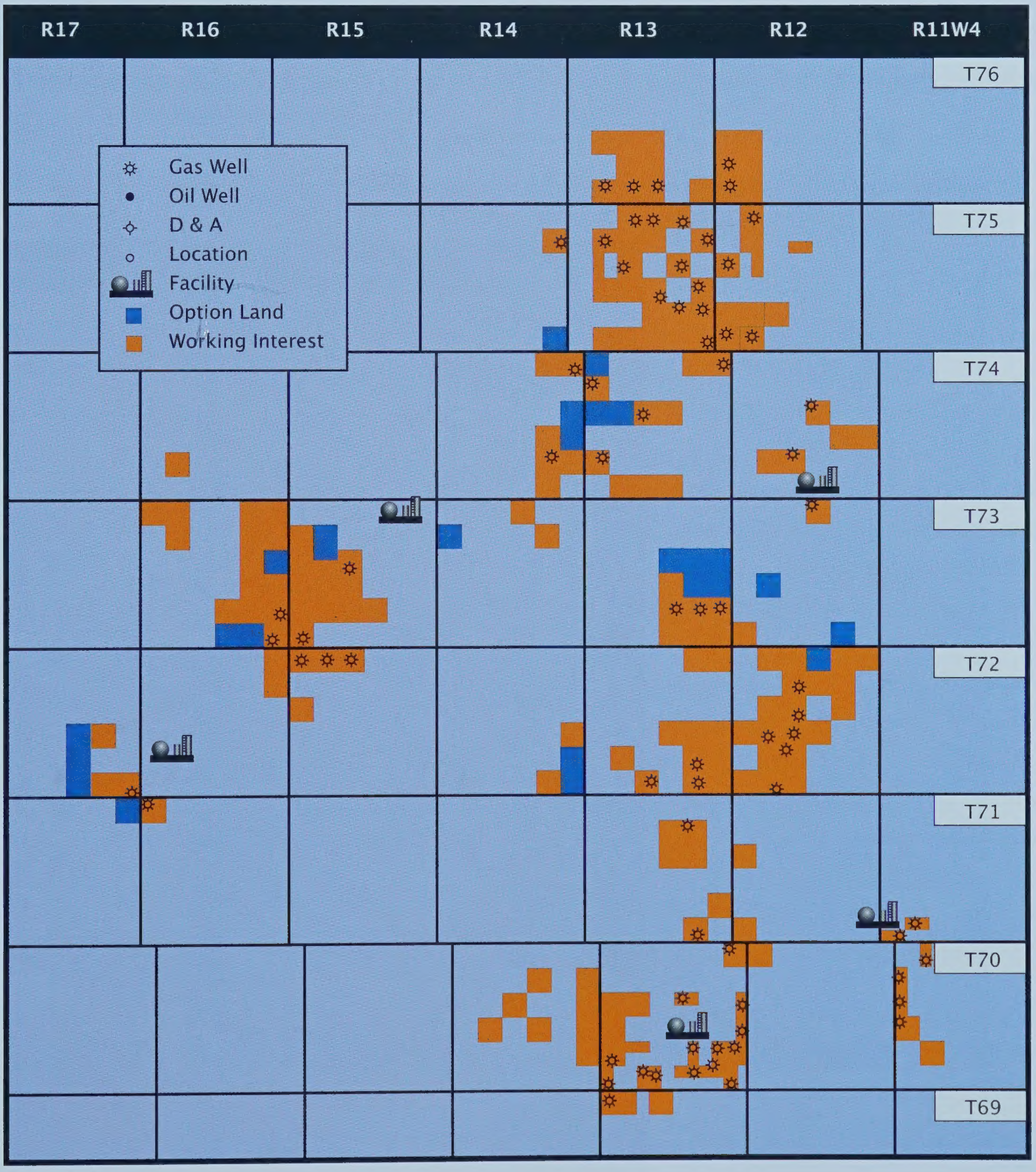
- Multi-zone, shallow, sweet natural gas plays contained within the Grosmont, Wabiskaw and McMurray Formations in eastern Alberta (including Tweedie/Wappau/Nixon, Liege/MacKay and Hanna/Garden).
- Multi-zone, shallow, sweet natural gas plays contained within the Edmonton Group formations in west-central Alberta (including Cygnet/Sylvan/Garrington, Pembina/Wilson Creek and Niton); and
- Multi-zone, medium depth, liquids-rich natural gas and light oil plays in west-central Alberta (including Crossfield/Olds, Pembina/Wilson Creek and Edson);

Eastern Alberta Operations

- Sweet natural gas, mutiple targets to 500m (1,500ft)
- 67% of TriQuest Established Reserves
- Drilled 90 (55 net) wells in 2002 and Q1 2003
- 60% average interest in 206 sections of undeveloped land
- Exposure to 400 sections (working interest + option)

Tweedie/Wappau/Nixon

The Tweedie/ Wappau/ Nixon area is located approximately 100 miles northeast of Edmonton. Geological targets for this area include the Grand Rapids, Wabiskaw and McMurray Formations at depths between 200 and 500 metres. The Grand Rapids and McMurray Formations are structurally controlled and can be targeted using 2-D seismic. The Company has access to 400 miles of seismic data to identify these targets. Average initial rates per well vary between 100 and 300 mcf/d (17 and 50 boe/d); while a number of wells



in the area have produced at rates exceeding 1.0 mmcf/d (167 boe/d). The sweet natural gas found in this area requires only dehydration and compression before being delivered to sales pipelines.

During the 1st quarter of 2002, TriQuest drilled 53 (net 46.3) wells, resulting in 38 gas wells, for a 72% success rate. While most production did not come on steam until mid 2nd quarter, for the calendar year 2002 production averaged 3,600 mcf/d generating $3,400,000 operating income.

During the 1st quarter of 2003, TriQuest operated the drilling of a further 34 (net 26) wells, resulting in 20 gas wells, for a 60% success rate. Most production is expected to come on steam mid 2nd quarter. A further 12 wells have been identified for drilling next winter.

Tweedie/ Wappau/ Nixon represents 40% of TriQuest's current production and is expected to increase to 55% by the end of the second quarter 2003. This core area also represents 45% of TriQuest's Established Reserves.

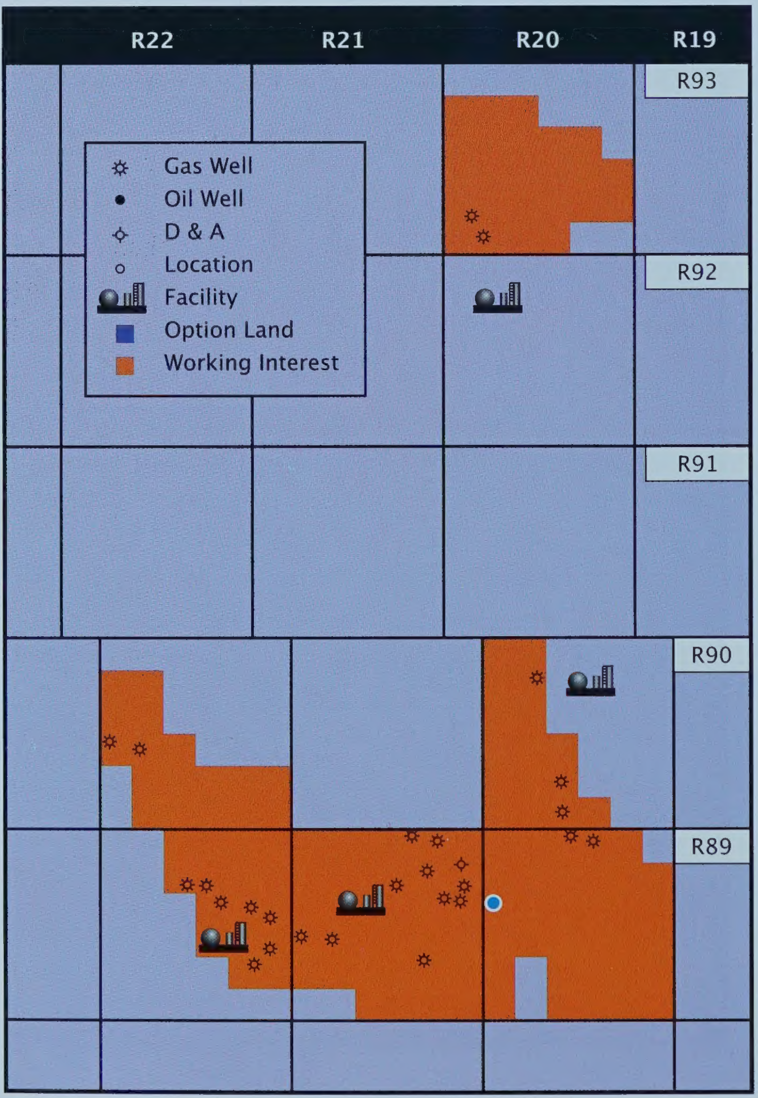
TriQuest has agreements with the area facility operator for gathering and processing at attractive rates that are fixed until December 31, 2006. TriQuest's natural gas production from the Tweedie/Wappau/Nixon area is sold on the spot market.

As at March 31, 2003, TriQuest had 16,600 gross undeveloped acres under option in addition to the 36,500 net undeveloped acres (average 66%) that has been earned or acquired to date. TriQuest is currently pursuing additional growth opportunities in Tweedie/Wappau/Nixon.

Liege/MacKay

Liege/ MacKay is located 220 miles north of Edmonton. TriQuest is the operator of the Liege/MacKay area and owns a 53% working interest in the gas gathering system, Liege compressor station and MacKay gas compression and processing facility. In this area, TriQuest also owns a 53% working interest in 102 sections of land and a 7% working interest in an adjoining 13 sections. Production is from the Grosmont and Nisku/McMurray Formations. During 2002, TriQuest made facility investments to improve operations, reduce operating costs and add third party volumes for compression and fee revenue.

During 2002, production averaged 1,000 mcf/d. Liege/ MacKay represents 8% of TriQuest's Established Reserves.



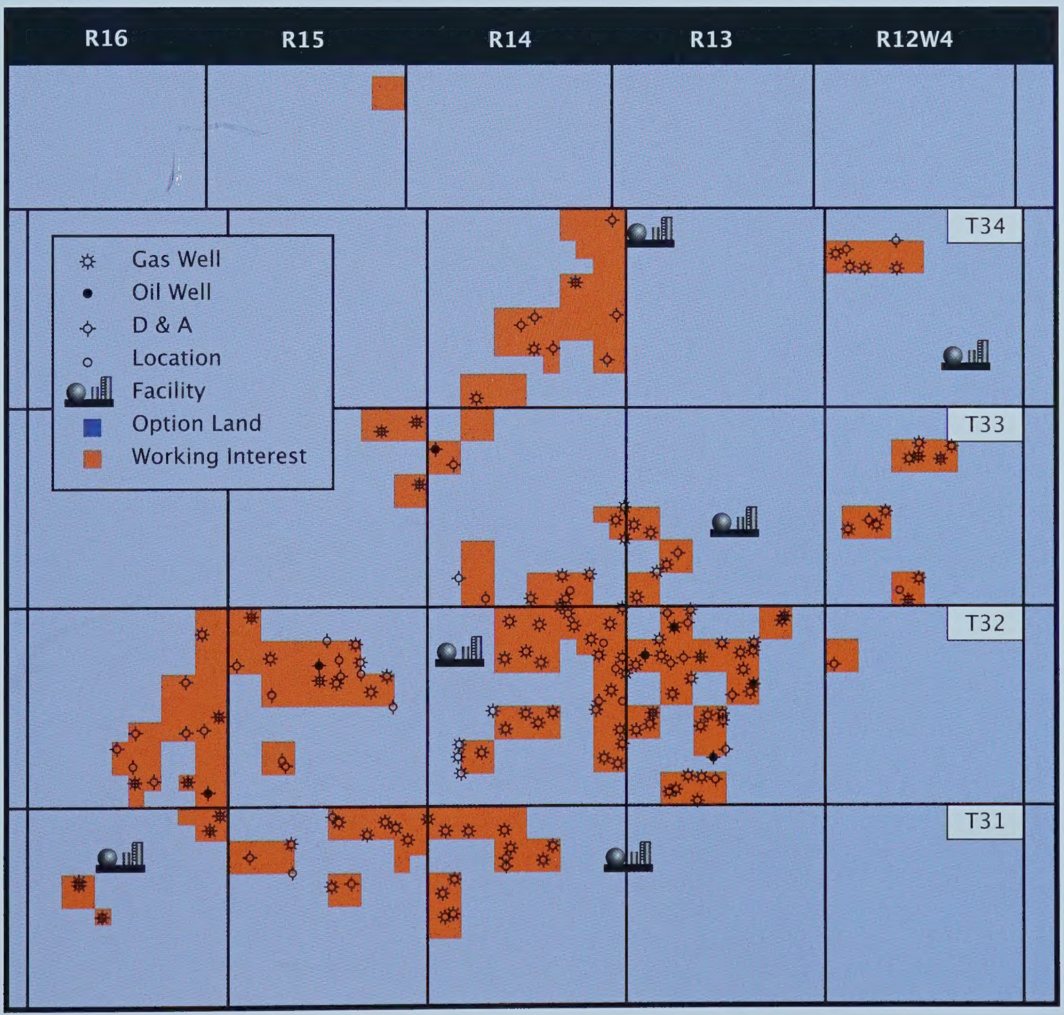
During the 1st quarter of 2003, the Company acquired additional working interests in the assets, re-completed 2 existing gas wells, tied in a third well to the production facilities and identified potential drilling locations for Q1 2004. The majority of production is dedicated under an aggregator contract with the remainder being sold on the spot market.

Hanna Garden

TriQuest has varying working interests ranging from 10% up to 37.5% in ninety- five sections in the Hanna Garden area, located 70 miles northeast of Calgary. Production is from the Second White Specks and the Belly River Formations. The Company owns a 7% interest in production facilities serving the area. A portion of the production is dedicated under an aggregator contract with the remainder sold on spot market.

During 2002, the Company's net production averaged 700 mcf/d from this area. Hanna Garden represents 14% of TriQuest's Established Reserves.

To date, the area has been drilled and produced largely on full and half section spacing. Most of the area has been approved for reduced production spacing units. TriQuest is investigating a significant possible infill drilling program for 2003 and 2004. Assuming one half section spacing is economically attractive, a further 58 gross wells could be drilled.



West-Central Alberta Operations

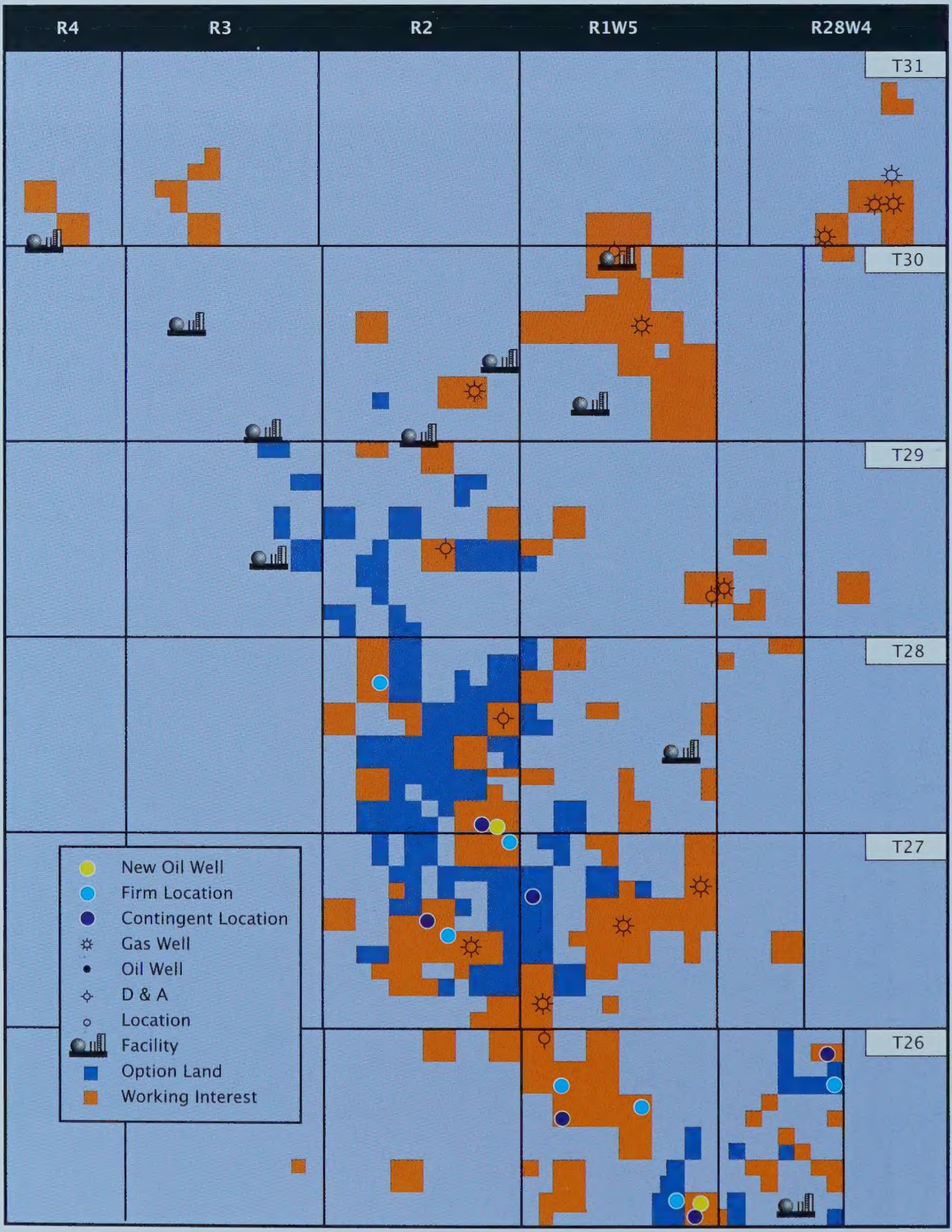
- Petroleum and liquids-rich gas production
- Multiple targets to 2,600m (8,500ft)
- Drilled or re-completed 13 (6.9 net) wells in 2002
- 55% average interest in 153 sections of undeveloped land
- 56 sections under option

Crossfield/Olds

Crossfield is located immediately north of Calgary. During 2002, TriQuest drilled 3 (1.9 net) wells to evaluate the Belly River, Viking, Ostracod and Elkton Formations. One of these wells is currently on production. One is being evaluated and the third is to be abandoned. During 2002, TriQuest brought seven new wells on production (including those drilled in 2001).TriQuest has a joint venture agreement in the area that also allows the Company to propose and drill new wells with a working interest between 50 and 100%. Currently TriQuest has exposure to 88 sections (42 undeveloped plus 46 under option) in the Crossfield/ Olds area.

During 2002, Crossfield/ Olds production averaged 1,200 mcfe/d and the area represents 10% of TriQuest's Established Reserves.

During 2003, TriQuest plans to drill or re-enter 10 wells. Most of these will be operated by TriQuest and evaluate prospective formations down to and including the Mississippian. Crossfield/ Olds makes up 20% of our planned 2003 capital budget.



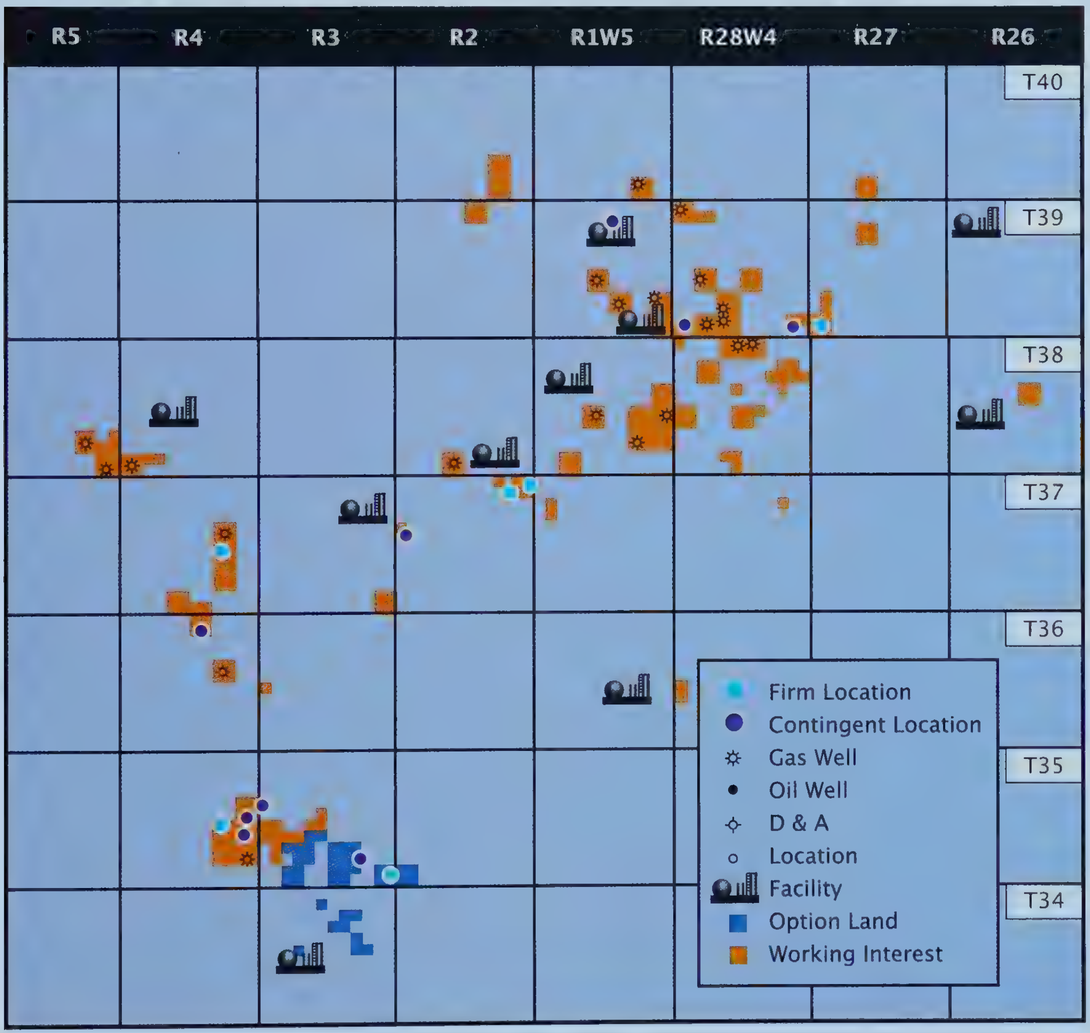
Cygnet/Sylvan/Garrington

TriQuest operates most of its production in the Cygnet/Sylvan/ Garrington area, located 90 miles north of Calgary. Strong natural gas pricing, improved technology and under-utilized production infrastructure in the area have driven the recent development of the Edmonton sands shallow gas play. TriQuest has accelerated the identification and evaluation of sweet natural gas reserves within the Edmonton Group which are found at depths of 1,000 metres or less.

During 2002 and Q1 2003, TriQuest has been succesful in capturing 40 sections of undeveloped land (average 45% working interest) plus 10 sections under option.

During the fifteen month period, TriQuest drilled 5 (2.2 net) wells with 100% success and brought 12 (6 net) wells on production. TriQuest has identified a further 30 potential locations for drilling within the upcoming 12 months.

All of TriQuest's production from this area is sold on the spot market. During 2002, Cygnet/ Sylvan/ Garrington production averaged 1,100 mcf/d, represents 10% of TriQuest's Established Reserves and 15% of current production.



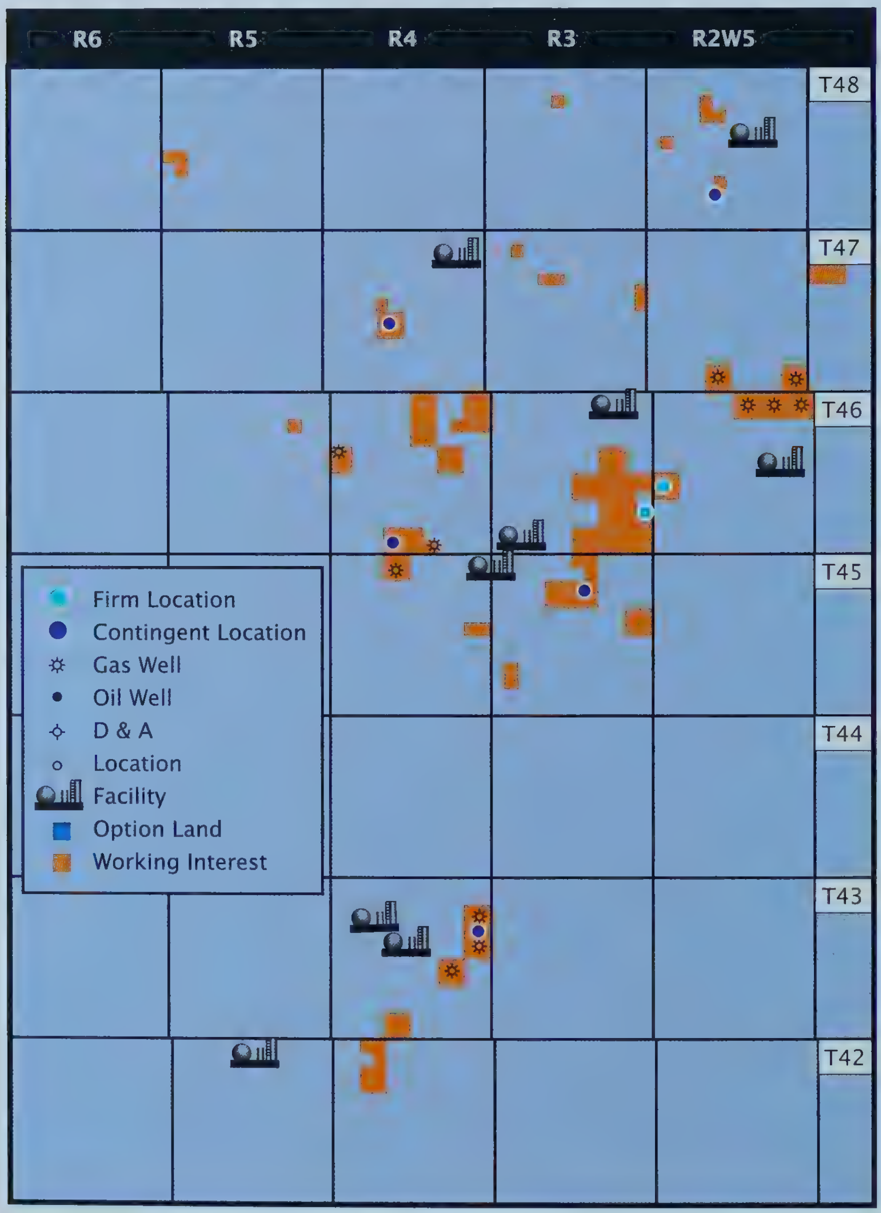
Pembina/Wilson Creek

The Pembina/ Wilson Creek area is located 120 miles northwest of Calgary. This area is prospective for light oil and liquids-rich natural gas in the Edmonton Group, Belly River, Glauconitic, Nordegg, Pekisko and Banff formations. TriQuest has an average 55% interest in 18,800 net undeveloped acres and an exposure to 37 sections within the Pembina/ Wilson Creek area.

During 2002, TriQuest successfully drilled or re-entered 3 (0.7 net) wells all of which are now on production.

Pembina/ Wilson Creek production averaged 700 mcf/d, and 30 bopd in 2002.

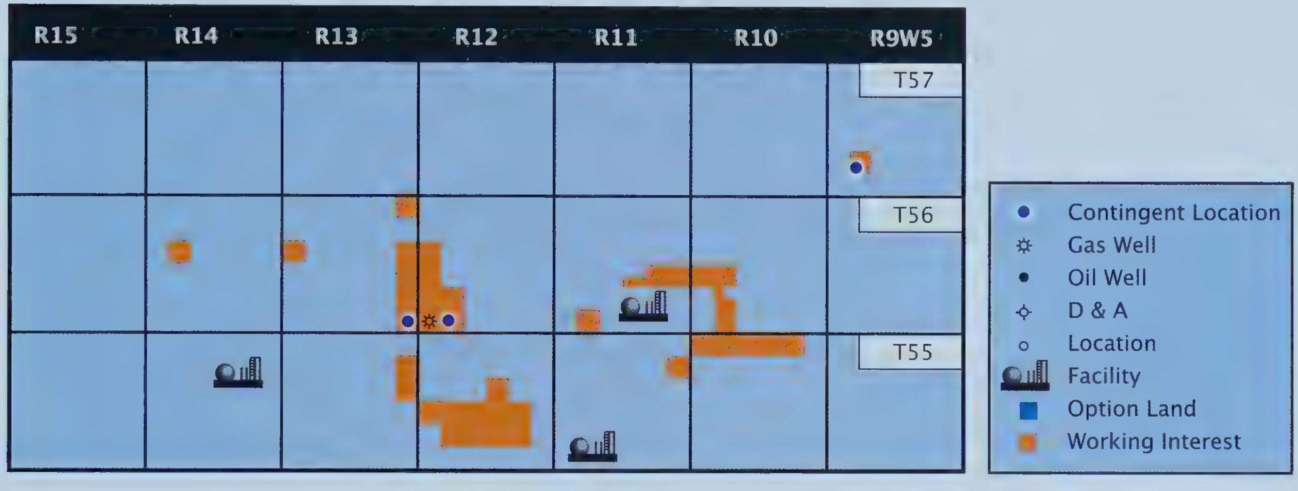
TriQuest has identified 20 locations for potential drilling in 2003 and 2004 in the Wilson Creek/Pembina area to evaluate the shallow and deeper gas targets.



Niton

The Niton area, located 90 miles west of Edmonton, is an exciting new prospect for TriQuest. The Niton area is prospective for natural gas in the Edmonton Group and Nordegg Formation. TriQuest has acquired a significant land position with 22,100 net undeveloped acres (average 92% working interest) and an exposure to 37 sections. TriQuest is currently pursuing additional growth opportunities in Niton.

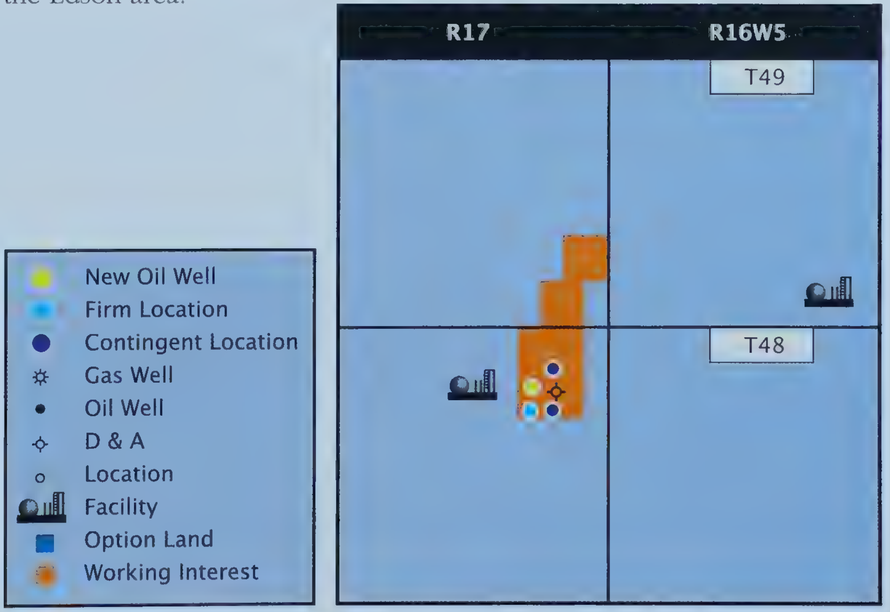
During 2002, TriQuest successfully drilled our first (1 net) well at Niton. This well is currently being placed on production. TriQuest has identified 10 locations for potential drilling in 2003 and 2004 in the Niton area.



Edson

The Edson area, located 130 miles west of Edmonton, is an exciting new light oil prospect for TriQuest. Edson is prospective for petroleum and natural gas in the Belly River Formation. TriQuest has earned and acquired 2,128 net undeveloped acres (average 70% working interest).

During 2002 and the 1st quarter of 2003, TriQuest drilled 3 (2 net) wells. The first well is a flowing oil well, the second was abandoned and the third awaits completion in Q2 2003 as an anticipated oil well. TriQuest has identified 5 locations for further drilling in 2003 and 2004 in the area and is pursuing additional growth opportunities in the Edson area.

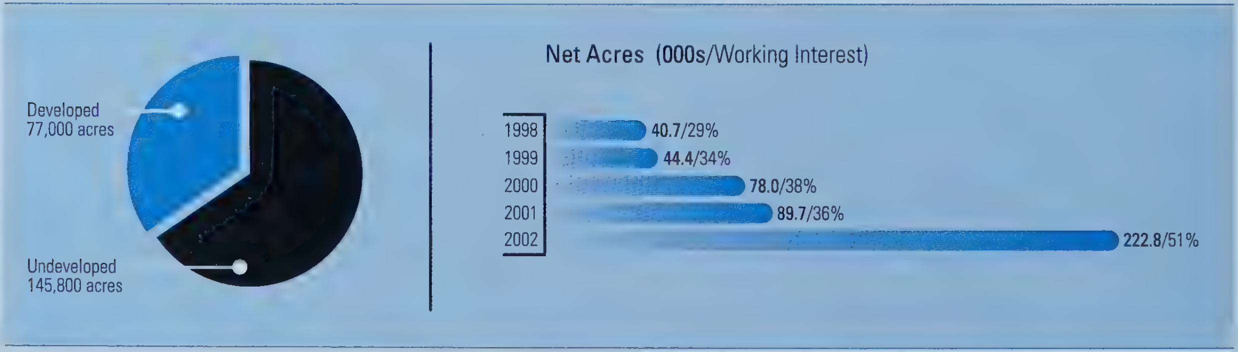


LAND

TriQuest is a company that grows by generating and capturing drilling prospects through the acquisition of interests in petroleum and natural gas rights at land sales and through farmin.

During 2002, TriQuest continued to build its land base, increasing its undeveloped acreage position by 135% to 145,800 net acres. Average working interest ownership is 53% in the undeveloped lands. Furthermore, the combination of TriQuest's undeveloped lands plus acreage under option provides the company with exposure to a total of 490 sections. Including the developed land base, TriQuest has under its control over 600 sections of land. Ninety-nine percent of TriQuest's lands are in Alberta.

	2002		2001	
Land Holdings (acres)	**Gross**	**Net**	**Gross**	**Net**
Land Summary by Type				
Developed	**165,000**	**77,000**	87,700	27,600
Undeveloped	**276,100**	**145,800**	162,400	62,100
Total	**441,100**	**222,800**	250,100	89,700
Royalty Lands	**38,800**		37,600	
Option Lands	**45,600**		19,200	
Land Summary by Province				
Alberta	**436,500**	**222,300**	245,500	89,200
British Columbia	**3,300**	**400**	3,300	400
Saskatchewan	**1,300**	**100**	1,300	100
	441,100	**222,800**	250,100	89,700



The following table indicates acreage that reaches the end of its term during the next three years. 12.5% of the Company's lands reach the end of term in 2003. Most of these lands are expected to be eligible for continuation beyond their term.

	Net Acreage	**Net Expiring Acreage**		
	Year-End 2002	**2003**	**2004**	**2005**
Alberta	222,300	28,000	31,600	19,100
British Columbia	400	0	0	0
Saskatchewan	100	0	0	0
Total	222,800	28,000	31,600	19,100

During the year, TriQuest purchased 26,800 net undeveloped acres of land at an average price of $45/acre, compared to the industry average price greater than $100/acre.

As at December 31, 2002, Charter Land Services Ltd., an independent land evaluation firm, evaluated TriQuest's net undeveloped lands at $7,021,000.

Production

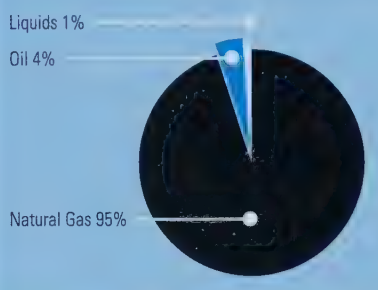
The Company's average production rate during 2002 was 8.13 mmcf/d of natural gas, 57 bbl/d of crude oil and 22 bbl/d of natural gas liquids. Throughout the Annual Report, production and reserves figures are reported on a gas and oil equivalency basis @ 6:1. On a gas equivalency basis, the average 2002 production rate was 8.60 mmcfe/d, a 206% increase compared to 2.81 mmcfe/d for 2001. On an oil equivalency basis, the average 2002 production rate was 1,434 boe/d compared to 467 boe/d during 2001.

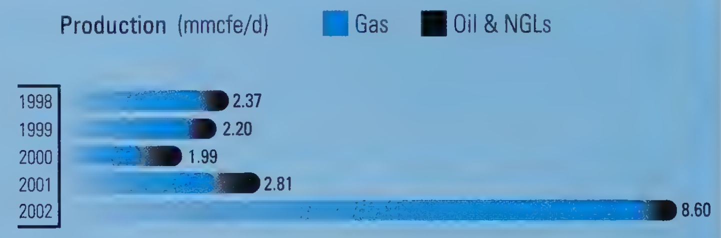
TriQuest has been very successful with its drilling projects in 2002, adding average production of approximately 5.75 mmcf/d of natural gas and 8 bopd of oil and natural gas liquids production to last year's totals. This includes new oil production from the Company's Edson property brought on stream in late December 2002. On an oil equivalency basis, this amounts to an increase of 967 boed over 2001 average production. Most of the new production was derived from drilling projects at Tweedie/Wappau in northeastern Alberta and the Cygnet/Sylvan and Crossfield/Olds areas of central Alberta.

The production mix was heavily weighted towards natural gas at 95%, with crude oil at 4% and natural gas liquids at 1%. This weighting is consistent with the Company's emphasis on exploring for natural gas and it is anticipated that this trend will continue. 98% of production was derived from Alberta with the balance coming from minor properties in Saskatchewan and British Columbia.

Average production rates for TriQuest's major producing areas are outlined below:

	2002			2001		
	Volume	**mmcfe/d @6:1**	**boe/d @ 6:1**	**Volume**	**mmcfe/d @6:1**	**boe/d @ 6:1**
Natural Gas (mmcf/d)						
Tweedie/Wappau	**3.57**	**3.57**	**595**	-	-	-
Cygnet/Sylvan	**1.10**	**1.10**	**183**	-	-	-
Crossfield/Olds	**1.09**	**1.09**	**182**	-	-	-
Liege/MacKay	**0.98**	**0.98**	**163**	1.10	1.10	183
Hanna Garden	**0.71**	**0.71**	**119**	0.61	0.61	102
Other	**0.68**	**0.68**	**113**	0.67	0.67	111
Total Natural Gas	**8.13**	**8.13**	**1,355**	2.38	2.38	396
Crude Oil (bbl/d)						
Wilson Creek	**30**	**0.18**	**30**	32	0.19	32
SW Success	**22**	**0.13**	**22**	28	0.17	28
Other	**5**	**0.03**	**5**	3	0.02	3
Total Crude Oil	**57**	**0.34**	**57**	63	0.38	63
Natural Gas Liquids (bbl/d)						
Other	**22**	**0.13**	**22**	8	0.05	8
Total Natural Liquids	**22**	**0.13**	**22**	8	0.05	8
Total Equivalents		**8.60**	**1,434**		2.81	467



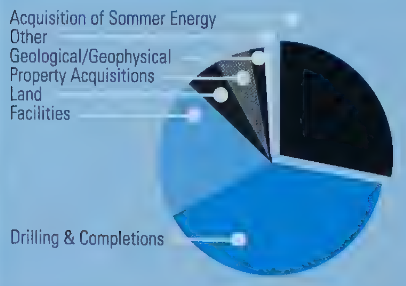


Capital

Due to the Company's activity in its northeastern and west-central Alberta core areas, capital expenditures during 2002 nearly tripled from 2001 to $32.1 million. Included in total expenditures is the acquisition of Sommer Energy Ltd. representing 28% of the total (net of cash, working capital and future tax liabilities acquired). Of the balance of total expenditures, 39% was dedicated towards drilling operations, 20% went towards the construction of well site and gathering facilities, and 5% was directed to the continued accumulation of a land base for future growth. For 2003, the Company has set a capital budget of $23.0 million, half of which will be invested in the Tweedie/Wappau area, with the remainder to be spent in west-central Alberta.

		Expenditures ($ millions)	% of Total Expenditures
Acquisition of Sommer Energy	*	9.0	28
Drilling & Completions		12.7	39
Facilities		6.4	20
Land		1.6	5
Property Acquisitions		1.6	5
Geological & Geophysical		0.7	2
Other		0.1	1
Total		32.1	100

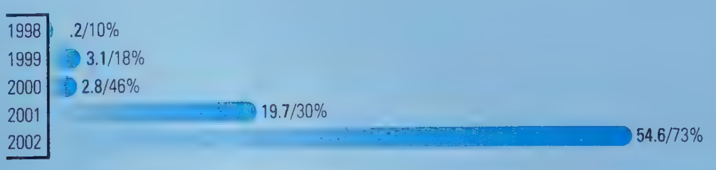
* Acquisition recorded net of cash, working capital and future income taxes.



During 2002, TriQuest participated in the drilling or re-completion of 75 gross wells (54.6 net), for an average working interest of 73%, all targeting gas reserves. Fifty-four (46.3 net) of the wells were drilled in Tweedie/Wappau. 13 wells (6.9 net) were drilled in our west-central Alberta core area. The remaining 8 (1.4 net) wells were drilled at Hanna. Overall, a 77% success rate was achieved.

	2002			2001		
	Gross		Net	Gross		Net
Exploration Wells						
Oil	**2**		**1.2**	1		0.3
Natural Gas	**3**		**1.5**	13		6.1
Dry & Abandoned	**1**		**1.0**	4		1.7
Total	**6**		**3.7**	18		8.1
Success Rate	**83%**		**73%**	78%		79%
Average Working Interest		**61.7%**			45%	
Operated by TriQuest		**6**			16	
Development Wells						
Oil	**0**		**0.0**	0		0.0
Natural Gas	**53**		**36.7**	42		10.6
Dry & Abandoned	**16**		**14.2**	5		1.0
Total	**69**		**50.9**	47		11.6
Success Rate	**73%**		**72%**	89%		91%
Average Working Interest		**75%**			25%	
Operated by TriQuest		**4**			14	
Total						
Oil	**2**		**1.2**	1		0.3
Natural Gas	**56**		**38.2**	55		16.7
Dry & Abandoned	**17**		**15.2**	9		2.7
Total	**75**		**54.6**	65		19.7
Success Rate	**77%**		**72%**	86%		86%
Average Working Interest		**73%**			30%	
Operated by TriQuest		**10**			30	

Drilling Activity (net wells/working interest)



Reserves Data and Future Net Revenue

All of TriQuest's reserves, production and future net revenue were independently evaluated by Gilbert Laustsen Jung Associates Ltd. ("GLJ"). The GLJ evaluation was prepared using the GLJ price forecast dated effective April 1, 2003, and these prices are shown on the table below for the initial five years of the evaluation.

		Crude Oil		Natural Gas	
		WTI Intermediate (US$/bbl)	Edmonton Reference (Cdn$/bbl)	Henry Hub (US$/mmbtu)	Average Alberta Plantgate (Cdn$/mmbtu)
Historical -	1998	14.42	20.36	2.16	1.94
	1999	19.29	27.69	2.32	2.48
	2000	30.22	44.56	4.33	4.50
	2001	25.97	39.40	4.05	5.41
	2002	26.08	40.33	3.36	3.88
Forecast -	2003	30.75	44.50	5.25	6.30
	2004	25.00	36.00	4.25	5.15
	2005	23.00	33.00	4.00	4.85
	2006	23.00	33.00	4.00	4.85
	2007	23.00	33.00	4.00	4.85

Presented below are summary tables of the Company's reserves as at December 31, 2002 based on GLJ's April 1, 2003 escalating price forecast.

"Gross reserves" are defined as the total remaining recoverable reserves owned by TriQuest before the deduction of royalties. "Net reserves" are defined as the Company's reserves after the deduction of all royalties. "Established Reserves" are defined as proved reserves plus 50% of probable reserves. It is important to note that reserves estimates, by their very nature, are subject to positive and negative revisions as additional information becomes available.

Gross Company Established Reserves were 4,616 mboe, of which 92% were natural gas and 82% were in the proven category. The reserve base at year-end 2002 is 90% greater than the 2,431 mboe carried at year-end 2001. Production of 523 mboe in 2002 was offset by new reserves developed in TriQuest's north-east and central Alberta core areas.

Corporation Share of Remaining Reserves and Present Worth Values at December 31, 2002
Escalating Price Forecast (as of April 1, 2003)

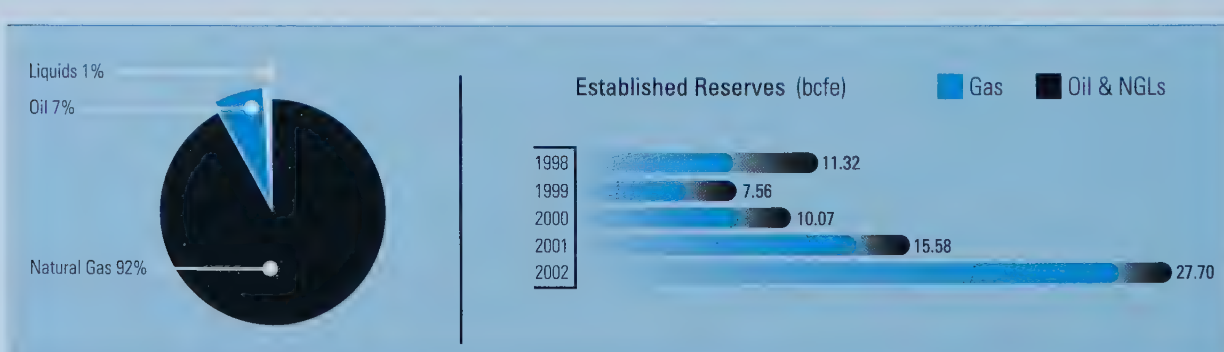
	Proved Producing	Proved Non-Producing	Total Proved	Proved & Probable	Established
Gross Corporation	202	32	234	396	315
Net After Royalties	166	29	196	325	260
Natural Gas (bcf)					
Gross Corporation	13.7	7.3	21.0	29.6	25.3
Net After Royalties	11.2	5.8	17.0	24.1	20.6
Natural Gas Liquids (mstb)					
Gross Corporation	60	12	72	101	87
Net After Royalties	41	8	49	68	59
Total Equivalent Reserves (mboe @ 6:1)					
mboe: Gross Corporation	2,543	1,258	3,800	2,431	4,616
Net After Royalties	2,082	1,003	3,084	4,410	3,747
Before Tax Present Value ($ millions)					
@ 0%	54.2	19.8	74.0	105.3	89.7
8%	40.2	14.8	55.0	72.2	63.9
10%	38.1	13.9	52.0	67.9	60.0
12%	36.2	13.2	49.4	63.8	56.6
15%	33.9	12.1	46.0	58.7	52.4
18%	32.0	11.2	43.2	54.4	48.8
20%	30.9	10.6	41.5	52.0	46.7
First 6 Years Before Tax Cash Flow ($ millions)					
2003	14.86	.63	15.49	16.20	15.84
2004	8.84	4.99	13.83	16.62	15.22
2005	6.09	3.96	10.05	13.17	11.61
2006	4.54	2.85	7.39	10.30	8.85
2007	3.21	1.91	5.12	7.59	6.36
2008	2.46	1.52	3.98	6.20	5.09

The table below indicates the future net revenue as at December 31, 2002 using forecast prices and costs. All evaluations of future net revenues are stated prior to provision for abandonment and site reclamation costs, income taxes, interest costs or general and administration expenses, but the figures do account for royalties and estimated future capital and operating costs, and include ARTC. It should not be assumed that the discounted future net revenues are representative of the fair market value of the reserves.

	Escalating Prices	
	Proved	**Established**
Future Gross Revenue ($ millions)	124.5	151.4
Less: Royalties, Net of ARTC	(17.5)	(21.6)
Development Costs	(5.9)	(7.0)
Operating Costs	(27.0)	(33.2)
Future Net Revenue	74.1	89.6
Future Net Revenue Discounted ($ millions)		
@ 0%	74.1	89.6
8%	55.0	63.9
10%	52.0	60.0
12%	49.4	56.6
15%	46.0	52.4
18%	43.2	48.8
20%	41.5	46.7

Development costs ($ millions) for the next 5 year period are shown below.

	Proved	**Established**
2003	5.1	5.8
2004	0.8	1.1
2005	0.0	0.0
2006	0.0	0.1
2007	0.0	0.0
	5.9	7.0



The reserve life index at year-end 2002, calculated on the basis of year-ending Established Reserves of 4,616 mboe and the 2002 average production rate of 1,434 boed, was 8.8 years. The replacement ratio for Established Reserves was 5.2 times 2002 production.

Net Asset Value

The following table summarizes the Company's net asset value at year end 2002 as measured with reference to the present value of future cash flows estimated by GLJ. Undeveloped land values are taken from an independent evaluation of the Company's lands at December 31, 2002 prepared by Charter Land Services Ltd.

	2002 Escalating Price			2001 @	%
	10%	12%	15%	15%	Change
Established Reserve Value	$59,977,000	$56,621,000	$52,363,000	$17,490,000	199
Undeveloped Land	7,021,000	7,021,000	7,021,000	2,548,000	176
Working Capital	240,607	240,607	240,607	3,888,687	(1,516)
Debt	0	0	0	0	0
Net Asset Value	$67,238,607	$63,882,607	$59,624,607	$23,926,687	149
Outstanding Shares	19,495,843	19,495,843	19,495,843	10,011,250	95
Net Asset Value per Share	$3.45	$3.28	$3.06	$2.39	28

Reserves Reconciliation

The following table shows a reconciliation of gross Company reserves from year end 2001 to 2002. Reserve additions for 2002 in the proved category amounted to 2,261,000 boe consisting of new gas reserves of 12.8 bcf (net of downward revisions at Tweedie/Wappau and Crossfield/Olds) and new oil reserves of 134,000 barrels. The reserve additions are primarily the result of the shallow gas program in northeastern Alberta and the new oil discoveries at Edson and Crossfield/Olds.

	Natural Gas (bcf)	Liquids (mstb)	Oil (mstb)	Total Equivalents mboe (@ 6:1)
Proved Reserves				
Beginning of Year	11.17	49	152	2,063
Revisions	(1.68)	2	8	(270)
Acquisitions/(Dispositions)	2.01	5	-	340
Discoveries/Extensions	12.43	24	95	2,191
Production	(2.97)	(8)	(21)	(524)
Sale of Reserves	0.00	0	-	-
Total Proved	20.96	72	234	3,800
Established Reserves				
Beginning of Year	13.09	61	188	2,431
Revisions	(2.20)	(1)	5	(362)
Acquisitions/(Dispositions)	2.18	6	-	369
Discoveries/Extensions	15.17	30	144	2,702
Production	(2.97)	(8)	(21)	(524)
Sale of Reserves	-	-	-	-
Total Established	25.27	88	316	4,616
Total Proved & Probable	29.60	102	396	5,431

Finding and Development Costs

Including the acquisition of Sommer Energy Ltd. in January 2002, the Company had capital expenditures of $29.10 million. The capital expenditures for this calculation have been reduced from $32.1 million to 29.1 million to eliminate the effect of approximately $3.0 million of future tax spiral on the acquisition of Sommer Energy Ltd. The Company's finding and development costs for 2002 were $12.90/boe ($2.15/mcfe) proved and $10.76/boe ($1.79/mcfe) Established.

	1-Year		3 Year	
	($/mcfe)	($/boe)	($/mcfe)	($/boe)
Proved	2.15	12.90	2.36	14.18
Established	1.79	10.76	2.02	12.10

Marketing

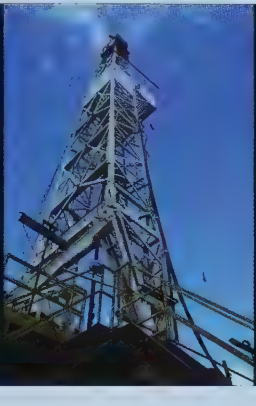
For 2002, TriQuest's production sales revenue totaled $12,600,000 (a 161% increase over 2001).

Natural gas sales made up 92% of TriQuest's production revenue in 2002. The average price for natural gas sold by TriQuest during 2002 was $3.92/mcf (a reduction from $4.56 in 2001). AECO spot market price for 2002 averaged $4.05/mcf. During December 2002, 82.5% of TriQuest's natural gas sales were delivered to the "spot" market in Alberta while the remaining 17.5% received aggregator netback pricing. As the Company grows its production with new drilling, sales to aggregators will continue to reduce as a percent of total sales.

Average prices for TriQuest's oil and natural gas liquids sales were $35.59 /bbl and $32.09/bbl respectively.

During 2002, TriQuest negotiated and entered into new production sales and marketing arrangements with select purchasers who have strong current and anticipated credit worthiness. TriQuest monitors these relationships continually while striving to obtain the best price and best service from the most financially secure purchasers.

During July 2002, TriQuest received prices as low as $1.35/ mcf, while in December, natural gas sales prices averaged $5.50/mcf. To ensure an element of price certainty and capital protection given the increasingly volatile nature of the gas market, TriQuest entered into costless collars and fixed pricing contracts starting in November 2002. The average put price for all of these contracts is $4.86 and the average call price is $5.71. The amount hedged at year end was 4,000 Gj/day, which represented approximately 38% of the Company's production. As part of TriQuest's risk management, the Company may hedge up to a maximum of 50% of its current and anticipated net production. Currently the Company hedge contracts all expire by October 31, 2003. As at December 31, 2002, if the Company were to terminate its hedge contracts, a payment of $339,000 would have been required.



Management's Discussion *and* Analysis

Management's discussion and analysis ("MD&A") should be read in conjunction with the Company's audited financial statements for the years ended December 31, 2002 and 2001. The MD&A provides detail and information on the financial and operating results for 2002 compared to 2001 and also provides an outlook for 2003. Management estimates and expectations for 2003 are based on assumptions about future events. Actual results and events will vary from these estimates and the variances may be significant.

Financial Highlights

	2002		2001	
	$	$/mcfe(1)	$	$/mcfe(1)
Revenue(2)	**10,391,163**	**3.31**	4,352,834	4.25
Expenses				
Production	**(3,128,617)**	**(1.00)**	(909,160)	(0.89)
General & Administrative	**(1,636,747)**	**(0.52)**	(853,240)	(0.83)
Capital & Other Taxes	**(115,426)**	**(0.04)**	(57,772)	(0.06)
Interest	**(82,451)**	**(0.03)**	-	-
Cash Flow From Operations	**5,427,922**	**1.72**	2,532,662	2.47
Depletion and Depreciation	**(4,607,833)**	**(1.47)**	(1,026,000)	(1.00)
Site Restoration	**(234,782)**	**(0.07)**	(70,000)	(0.07)
Future Income Taxes	**(216,883)**	**(0.07)**	(504,626)	(0.49)
Net Earnings	**368,424**	**0.11**	932,036	0.91
Per Share(3) Earnings				
Basic	**$0.02**		$0.11	
Diluted	**$0.02**		$0.10	
Cash Flow(4)				
Basic	**$0.32**		$0.29	
Diluted	**$0.31**		$0.28	
Capital Expenditures	**23,033,404**		11,131,004	
Year-End Working Capital	**240,607**		3,888,687	
Debt	**0**		0	
Average Production (mmcfe/d)	**8.60**		2.81	

Notes:

(1) Oil and natural gas liquids have been converted on the basis of 6 mcf per bbl.

(2) Revenue is after consideration of royalties, and includes interest income.

(3) Per share earnings and cash flow figures for 2001 have been adjusted to reflect a 1 for 4 share consolidation in Nov. 2002.

(4) Cash flow per share is calculated based on cash flow from operations before changes in non-cash working capital. Cash flow from operations is not a recognized measure under generally accepted accounting principles ("GAAP"). Management believes that in addition to net earnings, cash flow from operations is a useful supplemental measure. Investors should be cautioned, however, that cash flow from operations should not be construed as an alternative to net earnings determined in accordance with GAAP as an indicator of the Company's performance. The method of determining cash flow from operations may differ from other companies and, accordingly, may not be comparable to measures used by other companies.

Operating Netbacks

	2002			2001		
	$	%	($/mcfe)	$	%	($/mcfe)
Oil & Gas Sales Revenue	**12,612,215**	**100.0**	**4.02**	4,826,275	100.0	4.71
Royalties, net of ARTC	**(2,242,082)**	**(17.8)**	**(0.71)**	(734,464)	(15.2)	(0.72)
Production Expenses	**(3,128,617)**	**(24.8)**	**(1.00)**	(909,160)	(18.8)	(0.89)
Operating Netback	**7,241,516**	**57.4**	**2.31**	3,182,651	66.0	3.10

Revenue

The Company's gross oil and gas sales revenue for 2002 more than doubled for a total of $12.6 million, an increase of 161% over the comparable 2001 figure of $4.8 million. The revenue increase was due to increased average production in 2002 (8.60 mmcfe/d or 1,434 boe/d), which was 207% higher than in 2001 (2.81 mmcfe/d or 467 boe/d), offset by average commodity prices, which were 14% lower in 2002 ($4.02/mcfe) than in 2001 ($4.71/mcfe).

	Average Commodity Prices		Percent of Revenue	
	2002	2001	2002	2001
Natural Gas	**$3.92/mcf**	$4.56/mcf	92%	83%
Oil	**$35.59/bbl**	$31.84/bbl	6%	15%
Natural Gas Liquids	**$32.09/bbl**	$30.83/bbl	2%	2%
Natural Gas Equivalent	**$4.02/mcfe**	$4.71/mcfe		
Oil Equivalent	**$24.12/boe**	$28.26/boe		

During 2002, revenue resulting from the sale of natural gas accounted for 92% of the gross oil and gas sales revenue, compared to 83% for the previous year. The corresponding figures for oil were 6% in 2001 compared to 15% in 2001. The sale of natural gas liquids accounted for the remainder of revenue during both 2002 and 2001. The increase in natural gas revenue contribution is consistent with the Company's strong exploration focus for natural gas.

Interest income in 2002 was negligible compared to $0.3 million for the year ended 2001. Compared to 2001, the Company used bank borrowings to finance its drilling activities and accordingly, the Company incurred interest expense in the amount of $0.1 million and only earned marginal amounts on surplus cash. The Company expects interest expense to increase in 2003 as it draws against its loan facility to finance the 2003 capital program.

Royalties

Crown, freehold and overriding royalties paid during 2002 totaled $2.2 million ($0.71/mcfe or 17.8% of gross oil and gas sales revenue), net of Alberta royalty tax credit ("ARTC"). The corresponding amount for 2001 was $0.7 million ($0.72/mcfe or 15.2% of gross oil and gas sales revenue). This 205% increase in royalty expense from 2001 to 2002 is primarily due to the 206% increase in average production rates, offset by the 14% drop in average commodity prices.

ARTC reduced Crown royalties by $0.3 million ($0.11 /mcfe or 2.7% of gross oil and gas sales revenue) compared to a negligible amount in 2001. The substantial increase in ARTC is due to production derived from our west-central and northeastern Alberta properties. The Company expects that it will reach its full entitlement under the rules governing the ARTC during the year ended December 31, 2003.

Production Expenses

Net operating costs during 2002 were $3.1 million ($1.00/mcfe or 24.8% of gross oil and gas sales revenue), compared to $0.9 million ($0.89/mcfe or 18.8% of gross oil and gas sales revenue) during 2001. The main reason for the 244% increase in production expenses over 2001 is because of the large increase in production since most production costs vary with production. The increase in per unit expense from $0.89/mcfe in 2001 to $1.00/mcfe in 2002 was due to substantial one-time overhaul costs in the amount of $0.3 million at the Company operated Liege McKay gas plant in early 2002 that were charged to production expenses. Production expenses for the fourth quarter 2002 were $0.80/mcfe as a result of new production brought on stream in the quarter. The Company expects its yearly average per unit production expenses to decline from 2002 levels as anticipated new production from the 2003 drilling program is brought on stream.

General and Administrative Expenses

General and administrative ("G&A") expenses during 2002, net of overhead recoveries, were $1.6 million, up $0.7 million or 92% over the 2001 level of $0.9 million. The increase is the result of additional staffing required to manage the larger number of wells owned by the Company compared to 2001. G&A was 13.0% of gross oil and gas sales in 2002 compared to 17.7% in 2001. On a per unit basis, G&A decreased 37% from $0.83/mcfe in 2001 to $0.52/mcfe in 2002, primarily because of the increase in the average production rate

($, except per mcfe figures)	2002	2001
Gross G&A Expenses	**2,039,331**	1,229,946
Overhead Recoveries from Joint Venture Partners	**(402,584)**	(376,706)
Net G&A Expenses	**1,636,747**	853,240
Net G&A ($/mcfe)	**0.52**	0.83

Cash Flow From Operations

The table below indicates the Corporate netbacks generated by the Company during 2002 and 2001.

	2002			2001		
	$	%	($/mcfe)	$	%	($/mcfe)
Operating Netback	**7,241,516**	**57.4**	**2.31**	3,182,651	66.0	3.10
G&A	**(1,636,747)**	**(13.0)**	**(0.52)**	(853,240)	(17.7)	(0.83)
Interest	**(82,452)**	**(0.6)**	**(0.03)**			
Capital & Other Taxes	**(115,426)**	**(0.9)**	**(0.04)**	(57,772)	(1.2)	(0.06)
Operating Netback	**5,406,891**	**42.9**	**1.72**	2,271,639	47.1	2.22
Other Income	**21,030**	**0.2**	**0.01**	261,023	5.5	0.25
Cash Flow From Operations	**5,427,922**	**43.1**	**1.73**	2,532,662	52.6	2.47

Depletion, Depreciation and Site Restoration

Depletion and depreciation charges for 2002 amounted to $4.6 million. This compares to $1.0 million for 2001. The increase from 2001 is due primarily to higher production volumes and higher per unit depletion charges. In addition, the acquisition of Sommer Energy Ltd. resulted in an increase in the depletion rate because of the impact of a future tax "spiral calculation" to equalize future tax liabilities with the tax base of the assets acquired. On a per unit basis, 2002 depletion and depreciation was $1.47/mcfe compared to $1.00/mcfe in 2001. The Company expects the per unit costs to decline over time as we gain more production experience on our newer producing properties which will, in turn, provide our reserves evaluators more information to forecast production declines and ultimate recoveries on these properties.

Future site restoration charges amounted to $0.2 million compared to $0.1 million in 2001. The increase is due to 110.8 net wells for which abandonment costs will be incurred contrasted with 53.4 net wells in 2001. The Company examines each well it has an interest in and estimates an amount that would be required to abandon and restore each site. These amounts are accumulated and an annual provision is calculated based on the depletion rate.

The following table summarizes the abandonment and reclamation costs as at year-end 2002.

Number of Net Wells for Which Costs Will be Incurred		110.8
Number of Net Facilities for Which Costs Will be Incurred		1.1
Expected Future Abandonment and Reclamation Costs		$2.2 million
Costs Incurred During Year		$0.0 million
Abandonment and Reclamation Costs Accrued as at Year-End		$0.4 million
Abandonment and Reclamation Costs Expected to be Incurred in:	2003	$20,000
	2004	$40,000
	2005	$40,000

Income Taxes

The provision for future income tax decreased 57% to $0.2 million in 2002 from $0.5 million in 2001, due primarily to a decline natural gas prices, coupled with a reduction in the Alberta income tax rate.

In 2002, the Company was successful in adding significantly to the balances available for deduction against future taxable income, thereby extending the Company's tax horizon. With the drilling expenditures planned for 2003, it is anticipated that the Company will not be cash-taxable in 2003 or 2004.

The following table outlines the Company's year-end available deductions from future taxes, after anticipated deductions necessary to reduce 2002 taxable income to zero.

	Rate	2002	2001
Cumulative Canadian Oil & Gas Property Expense (COGPE)	10%	$5,063,000	$3,797,000
Cumulative Canadian Development Expense (CDE)	30%	7,772,000	2,411,000
Cumulative Canadian Exploration Expense (CEE)	100%	4,840,000	4,862,000
Total Resource Pools		$17,675,000	$11,070,000
Undepreciated Capital and Other Cost Pools	20-30%	8,599,000	2,325,000
Undeducted Share Issue Costs	20%	1,094,000	346,000
Non-Capital Loss Carried Forward	100%	-	126,000
Total		$27,368,000	$13,867,000

Earnings and Cash Flow

Earnings for 2002 were $0.4 million ($0.02 per basic or diluted share), down 60% from the corresponding 2001 level of $0.9 million ($0.11 per basic share and $0.10 per diluted share). The primary reasons for this earnings decrease related to increased depletion as a result of the future income tax spiral calculation from the Sommer Energy acquisition and increased production expenses offset by increased production revenue.

The Company had 2002 cash flow from operations of $5.4 million ($0.32 per basic share and $0.31 per diluted share), a 114% increase from the corresponding 2001 figure of $2.5 million ($0.29 per basic share and $0.28 per diluted share). The increase in cash flow from operations is due primarily to increased production volumes. The per share amounts did not increase to the same degree as the dollar value of cash flow from

operations due to the increase in the number of outstanding shares. During the year the Company issued shares for the Sommer Energy Ltd. acquisition and for the equity financing completed during the fourth quarter.

Ceiling Test

As required by the Canadian Institute of Chartered Accountants' full cost accounting guideline, the ceiling test ensures that the net book value of the petroleum and natural gas properties does not exceed the undiscounted estimated future net revenue of the Company's proved reserves. At December 31, 2002, using year-end pricing held constant throughout the life of the reserves, there was no impairment in the net book value of the property, plant and equipment of the Company. The prices used for the ceiling test were \$5.70/mcf for natural gas, \$39.33/bbl for oil and \$36.66/bbl for natural gas liquids.

Liquidity and Capital Resources

At year-end 2002, accounts receivable were \$3.6 million, a 51% decrease from the corresponding figure of \$7.4 million at year-end 2001. Of the 2002 figure, \$0.9 million (2000 - \$5.7 million) pertained to joint venture billings receivable for capital projects that the Company operated. The change in the composition of accounts receivable pertains primarily to increased revenue receivable at year end 2002 combined with the Company having larger working interests in its projects compared to 2001, thereby reducing the amounts due from joint venture partners.

Accounts payable at year-end of \$7.0 million were up 75% over the 2001 figure of \$4.0 million. Of the 2002 figure, \$5.6 million (2001 - \$0.5 million) pertained to amounts payable for capital projects on both operated and non-operated properties. The increase in accounts payable resulted primarily from the expansion in operational activity and the resulting capital expenditures combined with a larger number of properties in 2002 compared to 2001.

TriQuest's ability to grow is based, in part, on its ability to generate prospects and invest significant amounts of capital for its exploration, development and acquisition activities. In 2002, the Company's capital expenditures of \$23.1 million plus the acquisition of Sommer Energy Ltd. ("Sommer") for \$12.5 million (2001 - \$11.1 million) were funded by working capital, cash flow from operations and new equity financing. In January of 2002, the Company issued \$12.5 million of equity to acquire all of the outstanding shares of Sommer. The acquisition of Sommer included cash of \$4.4 million and additional working capital of \$1.9 million. In November of 2002 the Company completed an \$8.0 million equity financing consisting of \$4.0 million of flow-through shares and \$4.0 million of common shares by way of private placement to further fund the fall 2002 and winter 2003 capital programs. Additional equity financings may be considered during 2003 if market conditions permit.

The Company utilized a revolving credit facility with its bankers to fund any shortfall of cash requirements during the year. All outstanding debt balances were repaid following the November 2002 equity financing. The Company has a \$10.0 million revolving credit facility with a Canadian chartered bank that is available

to fund a portion of the 2003 capital program. Subject to need, the Company may look to extend the size of this facility.

With its strong cash flow and unused credit lines, the Company is well positioned to execute its $23.0 million capital budget for 2003 as approved by the board of directors.

The following table compares the additions and acquisitions for 2002 and 2001 and how they were funded:

	2002	2001
Additions and Acquisitions:		
Additions to Property, Plant & Equipment	**$21,582,133**	$11,080,964
Acquisition of Sommer Energy Ltd. net of working capital and future income taxes acquired	**8,972,071**	-
Acquisition of Property, Plant & Equipment	**1,592,926**	50,040
	$32,147,130	$11,131,004
Funded By:		
Cash Flow from Operations	**$5,427,922**	$2,532,662
Issuance of Share Capital for Sommer Energy Ltd.	**12,415,000**	-
Issuance of Share Capital for Cash, Net	**7,572,958**	3,000,000
Proceeds of Property Dispositions	**43,828**	-
Change in Working Capital	**3,826,105**	5,598,342
Future Income Taxes	**2,861,317**	-
	$32,147,130	$11,131,004

Financial Sensitivities

Corporate performance can be influenced heavily by external factors and most prominently, commodity prices. Because the Company's production is so heavily weighted towards gas production, cash flow and earnings are much more sensitive to changes in gas prices and volumes than to changes in oil and NGL prices and volumes. Incremental changes to each of these factors would have had the following effects on 2002 cash flow and earnings:

Factor	Sensitivity	Cash Flow	Earnings
Prices:			
Natural Gas	CDN $0.10 per mcf	$128,000	$10,000
Oil & Natural Gas Liquids	U.S. $1.00/bbl in WTI	$9,000	$1,000
Production:			
Natural Gas	1,000 mcf/day	$577,000	$37,000
Oil & Natural Gas Liquids	100 bbls/day	$30,000	$2,000

Common Share Trading

On November 14, 2002, the common shares of TriQuest were listed for trading on the Toronto Stock Exchange (TSX) under the symbol "TRI". Immediately prior to the listing on the TSX, a 1 new share for 4 old share consolidation was completed.

(Adjusted for 1 for 4 share Consolidation November 14, 2002)		**2002**	**2001**
Trading Volume:	Annual	**4,367,793**	915,560
	Monthly Average	**363,983**	76,550
	Annual Turnover	**25.3%**	10.4%
Trading Value:	Annual	**$12,309,677**	$2,254,173
Monthly Average		**$1,025,806**	$187,850
Share Price:	High	**$4.00**	$3.40
	Low	**$1.80**	$1.52
	Close	**$4.00**	$1.80
Outstanding Shares at Year-End		**19,495,843**	10,011,250
Outstanding Options		**1,711,111**	813,750
Fully Diluted Shares		**21,206,954**	10,825,000
Market Capitalization at Year-End		**$77,983,372**	$18,020,250

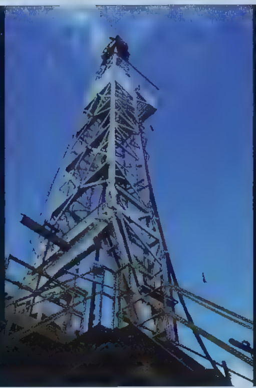
Business Risks and Risk Management

TriQuest is subject to operational and financial uncertainties, some of which are not controllable by the Company.

The Company is exposed to operational risk in the form of drilling, reservoir performance, competition, and environment and safety. The Company attempts to control operating risk by maintaining a disciplined approach to the implementation of the business strategy. Exploration risk is managed by employing an experienced technical staff and by conducting operations in the geographical and geological areas where it has expertise and experience. An extensive due diligence process is used to review the geological, geophysical, engineering and financial attractiveness of all operations. The actions of management are overseen by the Company's Board of Directors. Operatorship of properties allows the Company to control the manner, timing and cost of operations, and the Company intends, where possible, to continue to be the operator of jointly owned properties. In order to contend with its larger competitors, TriQuest relies on its technical expertise and its ability to make decisions quickly. TriQuest complies with all environmental and safety regulations under the jurisdictions that administer the policies where the Company operates. The Board has approved Environmental Protection and Safety plans, and the Company has a defined emergency response plan.

The Company is exposed to financial risk in the form of volatility in commodity prices, foreign exchange rates and interest rates. Financial risk is mitigated by maintaining a low debt to cash flow ratio when debt is outstanding. The Company uses short-term financial derivatives for hedging a portion of its production as its production base increases. The purpose of the hedging transactions is to ensure adequate cash flow to execute the Company's capital budget during the year. The Company uses various instruments including costless collars and fixed price contracts to reduce volatility on up to 40% of its production. See note 8 (c) in the financial statements for details of existing contracts.

The Company carries adequate insurance to cover identifiable and material risks and potential liabilities related to field and office activity, as well as coverage for personnel and directors executing their corporate responsibilities.



Management's Report

Report on Financial Data

The Company's financial statements and all of the information in this Annual Report are the responsibility of Management. The financial statements have been prepared by Management in accordance with Canadian generally accepted accounting principles. Other financial information presented elsewhere in this report is consistent with the financial statements and the underlying information from which these statements were prepared.

Management maintains systems of internal controls to ensure that the Company's assets are safeguarded, and that all transactions are authorized and properly recorded for the preparation of reliable financial statements.

The TriQuest Board of Directors has approved these financial statements upon the recommendation of the Audit Committee. KPMG LLP, the independent auditors appointed by the Shareholders, have audited the financial statements and expressed an opinion herein.

Report on Reserves Data

Independent evaluators have evaluated the Company's Reserves Data, and the reserve and value information prepared by Gilbert Laustsen Jung Associates Ltd. has been summarized in the section Reserves Data And Future Net Revenues. The Reserves Committee of the Board of Directors has: (a) reviewed the Company's procedures for assembling and reporting information associated with oil and gas producing activities and providing this information to the evaluator; (b) met with the independent evaluator to determine whether any restrictions placed by management affect the ability of the independent evaluator to report without reservation; and (c) reviewed the Reserves Data with Management and the independent evaluator. The Reserves Committee was satisfied with the process undertaken in the preparation of the evaluation, and on the recommendation of the Reserves Committee, the Board has approved the Reserves Data.

Bruce G. McIntyre
President & C.E.O.

Kelly D. Kerr
Vice-President, Finance & C.F.O.

April 23, 2003

Auditors' Report

To the Shareholders

We have audited the consolidated balance sheets of TriQuest Energy Corp. as at December 31, 2002 and 2001 and the consolidated statements of earnings and retained earnings and cash flows for the years then ended. These financial statements are the responsibility of the Company's management. Our responsibility is to express an opinion on these financial statements based on our audits.

We conducted our audits in accordance with Canadian generally accepted auditing standards. Those standards require that we plan and perform an audit to obtain reasonable assurance whether the financial statements are free of material misstatement. An audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements. An audit also includes assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall financial statement presentation.

In our opinion, these consolidated financial statements present fairly, in all material respects, the financial position of the Company as at December 31, 2002 and 2001 and the results of its operations and its cash flows for the years then ended in accordance with Canadian generally accepted accounting principles.

KPMG LLP.

Chartered Accountants

Calgary, Canada

April 11, 2003

Consolidated Balance Sheets

December 31, 2002 and 2001

	2002	2001
Assets		
Current assets:		
Cash and cash equivalents	**$ 3,643,398**	$ 670,075
Accounts receivable	**3,594,292**	7,443,642
	7,237,690	8,113,717
Property, plant and equipment (note 3)	**45,165,148**	17,669,679
	$ 52,402,838	$25,783,396
Liabilities and shareholders' equity		
Current liabilities:		
Accounts payable and accrued liabilities	**$ 6,997,083**	$ 4,047,006
Future site restoration (note 3)	**400,349**	165,567
Future income taxes (note 6)	**7,212,000**	2,718,400
Shareholders' equity:		
Share capital (note 5)	**34,984,161**	16,411,602
Retained earnings	**2,809,245**	2,440,821
	37,793,406	18,852,423
	$ 52,402,838	$25,783,396

See accompanying notes to consolidated financial statements.

On behalf of the Board:

Director

Director

Consolidated Statements of Earnings and Retained Earnings

Years ended December 31, 2002 and 2001

	2002	2001
Revenues:		
Petroleum and natural gas	**$ 12,612,215**	$ 4,826,275
Royalties, net of Alberta royalty tax credit	**(2,242,082)**	(734,464)
Interest and other	**21,030**	261,023
	10,391,163	4,352,834
Expenses:		
Depletion, depreciation and amortization	**4,607,833**	1,026,000
Production	**3,128,617**	909,160
General and administrative	**1,636,747**	853,240
Future site restoration	**234,782**	70,000
Interest	**82,451**	–
	9,690,430	2,858,400
Earnings before income taxes	**700,733**	1,494,434
Income taxes (note 6):		
Future	**216,883**	504,626
Capital and other	**115,426**	57,772
	332,309	562,398
Net earnings	**368,424**	932,036
Retained earnings, beginning of year	**2,440,821**	1,508,785
Retained earnings, end of year	**$ 2,809,245**	$ 2,440,821
Net earnings per share (note 7):		
Basic	**$ 0.02**	$ 0.11
Diluted	**$ 0.02**	$ 0.10

See accompanying notes to consolidated financial statements.

Consolidated Statements of Cash Flows

Years ended December 31, 2002 and 2001

	2002	2001
Cash provided by (used in):		
Operations:		
Net earnings	**$ 368,424**	$ 932,036
Items not involving cash:		
Depletion, depreciation and amortization	**4,607,833**	1,026,000
Future income taxes	**216,883**	504,626
Future site restoration	**234,782**	70,000
Cash flow from operations	**5,427,922**	2,532,662
Change in non-cash operating working capital	**(3,277,607)**	1,753,943
	2,150,315	4,286,605
Financing:		
Issuance of common shares, net of costs	**7,572,958**	3,000,000
Investing:		
Property, plant and equipment expenditures	**(21,582,133)**	(11,080,964)
Acquisition of oil and gas properties	**(1,592,926)**	(50,040)
Proceeds on sale of oil and gas properties	**43,828**	-
Acquisition (note 2)	**4,398,716**	-
Change in non-cash investing working capital	**11,982,565**	(3,838,653)
	(6,749,950)	(14,969,657)
Increase (decrease) in cash and cash equivalents	**2,973,323**	(7,683,052)
Cash and cash equivalents, beginning of year	**670,075**	8,353,127
Cash and cash equivalents, end of year	**$ 3,643,398**	$ 670,075
Cash flow from operations per share (note 7):		
Basic	**$ 0.32**	$ 0.29
Diluted	**$ 0.31**	$ 0.28
Supplemental cash flow information:		
Cash interest paid	**$ 82,452**	$ –
Cash capital and other taxes paid	**$ 44,707**	$ 57,772

See accompanying notes to consolidated financial statements.

Years ended December 31, 2002 and 2001

Nature of operations:

TriQuest Energy Corp. (the "Company") is a resource-based company engaged in the exploration for, and the development and production of natural gas, natural gas liquids and crude oil in Western Canada.

1. **Significant accounting policies:**

The financial statements of the Company have been prepared by management in accordance with generally accepted accounting principles in Canada. The preparation of financial statements in conformity with generally accepted account principles requires management to make estimates and assumptions that affect the amounts reported in the financial statements and accompanying notes. Actual results could differ from those estimates. The financial statements have, in management's opinion, been properly prepared using careful judgment with reasonable limits of materiality and within the framework of the significant accounting policies summarized below:

(a) Petroleum and natural gas operations:

The Company follows the full cost method of accounting whereby all costs associated with the exploration for and development of petroleum and natural gas reserves are capitalized. Such costs include land acquisition costs, geological and geophysical costs, exploration related administrative costs, lease rental costs on non-producing properties, costs of both productive and unproductive drilling and production equipment. Gains or losses are not recognized upon disposition of petroleum and natural gas properties unless crediting the proceeds against accumulated costs would result in a change in the depletion rate of 20% or more.

The accumulated costs, less the costs of acquisition of unproved properties, are depleted and depreciated using the unit-of-production method based on total proved reserves before royalties as determined by independent evaluators. Natural gas reserves and production are converted into equivalent barrels of oil based upon the estimated relative energy content.

The costs of acquiring and evaluating unproved properties are initially excluded from depletion calculations. These properties are assessed periodically to ascertain whether impairment has occurred. When proved reserves are assigned or the property is considered to be impaired, the cost of the property or the amount of impairment is added to the costs subject to depletion.

The net carrying amount of the Company's petroleum and natural gas properties is limited to a ceiling, being the aggregate of future net revenues from proved reserves, less future capital costs plus the costs of unproved properties, net of impairment allowances, less future site restoration costs, general and administrative costs, financing costs and income taxes. Further, net revenues are calculated using prices and costs in effect at the end of the relevant fiscal period without escalation or discounting.

(b) Interest in joint ventures:

Substantially all of the Company's oil and gas exploration and development activities are conducted jointly with others and, accordingly, the financial statements reflect only the Company's proportionate interest in such activities.

(c) Future site restoration costs:

Estimated future site restoration costs are provided for over the life of the estimated proven reserves on a unit-of-production basis. Costs are estimated by management in consultation with the Company's engineers based on current regulations, costs, technology and industry standards. The period charge is expensed and actual site restoration and abandonment expenditures are charged to the accumulated provision account as incurred.

(d) Risk management:

Financial instruments are utilized by the Company to manage its exposure to commodity price fluctuations. The Company does not utilize financial instruments for trading or speculative purposes.

The Company assesses the relationships between hedging instruments and hedged items, as well as its risk management objective and strategy for undertaking various hedge transactions. This process includes linking all derivatives to specific assets and liabilities on the balance sheet or to specific firm commitments. The Company also assesses, both at the hedge's inception and on an ongoing basis, whether the derivatives that are being used in hedging transactions are highly effective in offsetting changes in the cash flows of hedged items.

The Company uses costless collars and fixed price contracts to manage its exposure to natural gas price fluctuations. The net receipts or payments arising from these contracts are recognized in earnings as a component of petroleum and natural gas sales during the same period as the corresponding hedged position.

(e) Stock-Based Compensation:

The Company has a stock option plan, as described in note 5(c), and records consideration paid by employees or directors on the exercise of the stock options as a capital transaction.

Effective January 1, 2002, the Company prospectively adopted the new Canadian accounting standard relating to stock based compensation. For options or similar instruments granted to non-employees, an amount equal to the grant date fair value of the instruments will be recorded as a charge to earnings over the vesting period. For options granted to employees, the Company has elected not to use the fair value method but to disclose the impact of the fair value method on a proforma basis.

(f) Income taxes:

The Company uses the liability method of accounting for future income taxes. Under the liability method, future income tax assets and liabilities are determined based on "temporary differences" (differences between the accounting basis and the tax basis of the assets and liabilities), and are measured using the currently enacted, or substantively enacted, tax rates and laws expected to apply when these differences reverse. A valuation allowance is recorded against any future income tax assets if it is more likely than not that the asset will not be realized.

(g) Office furniture and equipment:

Office furniture and equipment is stated at cost. Depreciation is provided on a declining balance basis at a rate of 20% per annum.

(h) Per share amounts:

In calculating diluted net earnings per share, the Company follows the treasury stock method to determine the dilutive effect of stock options and other dilutive instruments. The dilutive effect is calculated by assuming that outstanding stock options were exercised and that the proceeds from such exercises were used to acquire common shares at the average market price during the year. Only "in the money" dilutive instruments impact the calculation.

(i) Flow-through shares:

Resource expenditure deductions for income tax purposes related to exploration and development activities funded by flow-through share arrangements are renounced to investors in accordance with income tax legislation. Future income tax liabilities are increased and capital stock is reduced by the estimated tax cost when the expenditures are renounced.

(j) Cash and cash equivalents:

The Company classifies cash and short term deposits with maturities of three months or less as cash and cash equivalents.

2. Business combination:

On January 30, 2002, the Company acquired all of the issued and outstanding shares of Sommer Energy Ltd. ("Sommer"), a company engaged in the exploration for, and development and production of natural gas and natural gas liquids in Alberta. The acquisition has been accounted for by the purchase method. Details of the acquisition are as follows:

Net assets acquired at assigned values:		
Working capital (including cash of $4,496,543)	$	6,402,073
Future income taxes		(2,861,317)
Property, plant and equipment		8,972,071
	$	12,512,827

Consideration:		
6.9 million common shares at an ascribed value of $1.80 per share (i)	$	12,415,000
Acquisition costs		97,827
	$	12,512,827

(i) After giving effect to the 1 for 4 share consolidation (see note 5).

3. Property, plant and equipment:

2002	Cost	Accumulated depletion, depreciation and amortization	Net book value
Exploration and development costs	$41,599,577	$5,967,120	$35,632,457
Production equipment and facilities	10,656,512	1,305,303	9,351,209
	52,256,089	7,272,423	44,983,666
Office furniture and equipment	319,524	138,042	181,482
	$52,575,613	$7,410,465	$45,165,148

2001			
Exploration and development costs	$16,907,138	$2,327,162	$14,579,976
Production equipment and facilities	3,385,027	417,338	2,967,689
	20,292,165	2,744,500	17,547,665
Office furniture and equipment	180,146	58,132	122,014
	$20,472,311	$2,802,632	$17,669,679

As at December 31, 2002, costs of acquiring undeveloped properties in the amount of $5,988,100 (2001 - $2,548,800) were excluded from depletion calculations.

As at December 31, 2002, the estimated future site restoration costs to be accrued over the life of the remaining proven reserves were approximately $2.2 million.

Accounts receivable include $858,893 (2001 - $5,706,145) pertaining to joint venture billings receivable for capital projects. Included in accounts payable is $5,610,579 (2001 - $534,905) relating to capital projects.

4. Bank debt:

The Company has available a $10 million revolving credit facility from a Canadian chartered bank with an extendible 364 day revolving period. If the facility is not renewed, all balances due are subject to a one year amortization term period. The facility is secured by a $50 million first floating charge debenture on all of the Company's assets. The facility bears interest at the bank's prime rate plus 0.25%. At December 31, 2002 and 2001, no amounts were drawn under the facility.

5. Share capital:

(a) Authorized:

(i) Unlimited number of common shares; and

(ii) Unlimited number of preferred shares, issuable in series, rights and privileges to be determined upon issue, of which none have been issued.

(b) Common shares issued and outstanding:

	Number of shares	Amount
Balance, December 31, 2000	8,761,250	$14,689,602
Flow-through shares issued for cash, net of future income tax of $1,278,000	1,250,000	1,722,000
Balance, December 31, 2001	10,011,250	16,411,602
Issued in exchange for Sommer	6,897,224	12,415,000
Issued for cash on exercise of stock options	142,925	211,016
Issued for cash pursuant to private placement	1,333,333	4,000,000
Flow-through shares issued for cash, net of future income tax of $1,684,000	1,111,111	2,316,000
Share issue costs, net of future income tax of $268,600	–	(369,457)
Balance, December 31, 2002	19,495,843	$34,984,161

On November 14, 2002, the Company consolidated its shares on the basis of 1 new common share for every 4 old common shares. Concurrent with the share consolidation, the Company listed its shares on the Toronto Stock Exchange. All of the per share amounts and share and option information has been retroactively presented.

The Company is required to incur $4.0 million, pursuant to the issuance of the flow through shares, on expenditures qualifying as Canadian exploration expense prior to December 31, 2003. At December 31, 2002, the Company had incurred $1.1 million of these qualifying expenditures.

(c) Stock option program:

The Company has a stock option program whereby employees, officers, directors and consultants are eligible to receive options. The maximum number of options which may be reserved for issuance under the options plan cannot exceed 10% of the issued and outstanding common shares. Under the program, the exercise price of each option equals the market price of the Company's stock on the date of grant. The options have a five year term and 1/3 vest on grant and then 1/3 vest on each of the first and second anniversaries of the grant date.

The following table summarizes the changes in the Company's stock option program (adjusted for 1 for 4 share consolidation):

	2002		2001	
	Number of options	Weighted average exercise price	Number of options	Weighted average exercise price
Outstanding at beginning of year	**813,750**	**$ 1.96**	795,000	$ 1.96
Granted	**1,040,286**	**2.31**	18,750	1.88
Exercised	**(142,925)**	**1.48**	–	–
Outstanding at year end	**1,711,111**	**$ 2.20**	813,750	$ 1.96
Exercisable at year end	**1,016,620**	**$ 2.16**	685,000	$ 2.05

The following table summarizes information about stock options outstanding and exercisable as at December 31, 2002:

	Options Outstanding			Options Exercisable	
Range of exercise prices	Number of options	Weighted average remaining contractual life	Weighted average exercise price	Number of options	Weighted average exercise price
		(years)			
$ 1.40 to $ 1.94	833,611	3.59	$ 1.78	390,787	$ 1.75
$ 1.95 to $ 2.49	500,000	1.71	2.25	500,000	2.25
$ 2.50 to $ 3.04	100,000	4.75	2.80	33,333	2.80
$ 3.05 to $ 3.60	277,500	4.80	3.20	92,500	3.20
$ 1.40 to $ 3.60	1,711,111	3.31	$ 2.20	1,016,620	$ 2.16

(d) Stock-based compensation:

Had compensation cost been determined based on the fair value method for awards made after December 31, 2001, the Company's earnings and earnings per share for the year ended December 31, 2002 would have been adjusted to pro forma amounts indicated below:

	As Reported	Pro Forma
Net earnings (loss)	$368,424	$(400,538)
Basic and diluted earnings (loss) per share	$0.02	$(0.02)

The weighted average fair value of options granted during the year ended December 31, 2002 was $1.42 per option using the Black-Scholes option pricing model with the following weighted average assumptions:

Risk free interest rate	5%
Expected life	5 years
Expected volatility	69%

6. **Taxes:**

The provision for taxes differs from the amount that would have been expected by applying corporate income tax rates to earnings before taxes as shown below:

	2002	2001
Earnings before taxes	**$ 700,733**	$ 1,494,434
Statutory income tax rate	**42.1%**	42.6%
Expected tax provision	**$ 295,008**	$ 636,629
Increase (decrease) in expected tax provision resulting from:		
Non-deductible crown charges	**634,427**	275,900
Resource allowance	**(660,682)**	(302,000)
Effect of reduction in tax rates	**(65,574)**	(42,000)
Other	**13,704**	(63,903)
Future income taxes	**216,883**	504,626
Capital and other taxes	**115,426**	57,772
	$ 332,309	$ 562,398

The components of the net future income tax liability are as follows:

	2002	2001
Future income tax liability:		
Property, plant and equipment	**$ 7,798,900**	$ 2,971,930
Less future income tax assets:		
Share issue costs	**460,500**	147,330
Future site restoration	**126,400**	52,700
Non-capital loss	**-**	53,500
	586,900	253,530
Net future income tax liability	**$ 7,212,000**	$ 2,718,400

Subject to confirmation by income tax authorities, the Company has estimated deductions available for tax purposes of $27.4 million outstanding as at December 31, 2002.

7. **Per share amounts:**

In computing diluted per share amounts, 547,606 (2001 – 146,932) shares were added to the 16,736,587 (2001 – 8,795,497) weighted average number of common shares outstanding during the year for the dilutive effect of stock options.

8. **Financial instruments:**

(a) Credit risk:

A significant portion of the Company's accounts receivable are from joint venture partners in the oil and gas industry and are subject to normal industry credit risks.

(b) Fair value of financial instruments:

The carrying value of the Company's financial instruments, being cash and cash equivalents, accounts receivable and accounts payable and accrued liabilities approximate their fair value due to their short maturity.

(c) Risk management:

The Company has a price risk management program whereby the natural gas price associated with a portion of its future production is locked into a range using contracts. The Company sells forward a portion of its future production through a combination of costless collar contracts and fixed price contracts with financial counterparties.

The contracts are subject to market risk from fluctuating natural gas prices.

At December 31, 2002, the Company had entered into the following financial contracts:

Contract Term	Volume Contract Type	Weighted Average Contracted (Gj/day)	Weighted Average Put Price ($/Gj)	Call Price ($/Gj)
Nov 02 – Mar 03	Collar	1,000	$5.000	$5.910
Dec 02 – Mar 03	Collar	2,000	$5.125	$6.080
Nov 02 – Oct 03	Fixed	1,000	$5.060	$5.060
Apr 03 – Oct 03	Collar	3,000	$4.583	$5.617

On December 31, 2002, a net settlement payment of $339,000 would have been necessary to terminate all contracts

9. Related party transactions:

The Company paid $nil (2001 - $90,000) for management and administrative services to a company with common directors. The transaction was in the normal course of operations and was recorded at the exchange amount.

Corporate Governance

The Toronto Stock Exchange requires each listed company to disclose its corporate governance practices with reference to guidelines set out in the "Report of The Toronto Stock Exchange Committee on Corporate Governance in Canada". These guidelines, which are not mandatory, deal with the constitution of boards of directors and board committees, their functions, their independence from management and other means of addressing corporate governance practices. The Board and Management consider good corporate governance to be central to maintaining effective and efficient corporate operations. However, given the history and nature of the Corporation's development, not all of the recommendations contained in the TSE Report have been followed. Listed below are the 14 guidelines proposed by the TSE Report and a brief discussion of the Corporation's compliance with the guidelines.

1. *The Board should explicitly assume responsibility for stewardship of the Corporation, and specifically for adoption of a strategic planning process, identification of principal risks, succession planning and monitoring, communications policy and integrity of internal control and management information systems.*

   The Board is responsible for the overall stewardship of the Company, planning, directing, and dealing with issues that are pivotal to determining corporate strategy and direction. The Board considers management development and succession programs, strategic business developments such as significant acquisitions, and financing proposals including the issuance of shares and other securities, as well as those matters requiring Board approval by law.

2. *A Majority of directors should be "unrelated" (free from conflicting interest).*

   The Board is comprised of six members, five of whom are independent and unrelated, and one is senior management of the Company. As a result, a majority of the members of the Board are unrelated members.

3. *Disclose for each director whether he or she is related, and how that conclusion was reached.*

   Mr. McIntyre (President and Chief Executive Officer) is the only related director and he would also be considered an inside director.

4. *Appointment of a Committee responsible for appointment/assessment of directors.*

   The Board has no formal recruitment process with respect to nominees to the Board, and, given the size of the Board, it has not yet formed a Corporate Governance Committee. The responsibility for recruitment is undertaken by management and is discussed informally with other Board members prior to candidates being proposed for appointment or election.

5. *Implement a process for assessing the effectiveness of the Board, its Committees and individual directors.*

The Board continually evaluates the effectiveness of itself. Due to the size of the Board, a separate committee has not been organized to fulfill this function.

6. *Provide orientation and education programs for new directors.*

TriQuest does not currently have any formal orientation and education programs for new directors, as the Company's activities are not sufficiently complex to require such programs.

7. *Consider reducing size of Board, with a view to improving effectiveness.*

A board of directors must have enough directors to carry out its duties efficiently while presenting a diversity of views and experiences. The Board believes that its current size and composition of six members reflects diversity and promotes effectiveness and efficiency.

8. *Review the compensation of directors in light of risks and responsibilities.*

The Board, through its Compensation Committee, periodically reviews the adequacy and form of the compensation of directors.

9. *Committees should generally be composed of outside directors, a majority of whom are unrelated.*

The TriQuest Board currently has an Audit Committee, Compensation Committee and a Reserves Committee, each of which is made up of three of the directors, all of whom are independent directors.

10. *Appoint a Committee responsible for approach to corporate governance issues.*

A separate Governance Committee has not been established. The Board as a whole is responsible for continued development of the Company's approach to the Governance Guidelines.

11. *The Board should develop position descriptions for the Board and for the chief executive officer, and the Board should approve or develop corporate objectives that the chief executive officer is responsible for meeting.*

To date, the Corporation has not developed position descriptions for the Board or the Chief Executive Officer. The Board currently sets the Corporation's annual objectives which become the objectives against which the Chief Executive Officer's performance is measured.

12. *Establish procedures to enable the Board to function independently of management.*

With the Board consisting of both a related director and a majority of unrelated directors, the Board has not been able to function totally independently of executive management. However, in matters that require independence of the Board from management, only the unrelated Board members take part in the decision making and evaluation.

13. *Establish an Audit Committee with a specifically defined mandate (all members should be non-management directors).*

The Audit Committee is composed of three directors (Messrs. Hotchkiss, Neugebauer and Wettstein), all of whom are independent directors. The Audit Committee has direct communication channels with the external auditors.

14. *Implement a system to enable individual directors to engage outside advisors, at Corporation's expense.*

TriQuest has no formal policy that allows outside directors to engage outside advisors at the Company's expense.

Five Year Highlights

	2002	2001	2000	1999	1998
Financial ($, except for per share information)					
Gross Oil & Gas Sales	**12,612,215**	4,826,275	3,687,745	2,166,295	1,741,132
Royalties, Net of ARTC	**(2,242,082)**	(734,464)	(576,310)	(368,735)	(121,667)
Production Expenses	**(3,128,617)**	(909,160)	(818,388)	(526,977)	(518,594)
Net Operating Income	**7,241,516**	3,182,651	2,293,047	1,270,583	1,100,871
Other Income	**21,030**	261,023	546,457	151,935	0
Interest Expense	**(82,451)**	0	0	(32,615)	(56,545)
Capital and Other Taxes	**(115,426)**	(57,772)	(13,000)	(13,000)	0
General & Administrative	**(1,636,747)**	(853,240)	(867,700)	(626,715)	(218,222)
Cash Flow From Operations	**5,427,922**	2,532,662	1,958,804	750,188	826,104
Depletion & Depreciation	**(4,607,833)**	(1,026,000)	(433,630)	(510,002)	(486,000)
Site Restoration	**(234,782)**	(70,000)	(65,500)	(87,449)	(7,000)
Future Income Taxes	**(216,883)**	(504,626)	(708,000)	(52,233)	(102,100)
Net Income:	**$ 368,424**	932,036	751,674	100,504	231,004
$/basic share	**0.02**	0.11	0.09	0.02	0.12
$/diluted share	**0.02**	0.10	0.09	0.02	0.12
Net Capital Expenditures	**32,103,302**	11,089,146	3,606,256	728,121	1,536,274
Long-Term-Debt @ Year-End	**0**	0	0	0	850,701
Shareholders' Equity	**37,793,406**	18,852,423	16,198,387	15,532,113	3,119,702
Working Capital @ Year-End	**240,607**	3,888,687	9,492,153	11,251,143	247,715
Share Price: High	**$4.00**	$3.40	$2.52	$4.00	$3.00
Low	**$1.80**	$1.52	$1.44	$0.92	$1.24
Close	**$4.00**	$1.80	$2.00	$2.40	$1.36
Trading Volume	**4,367,793**	915,560	1,177,063	202,270	129,050
Weighted Average Shares	**16,736,587**	8,795,497	8,795,256	4,234,805	1,959,134
Basic Shares @ Year-End	**19,495,843**	10,011,250	8,761,250	8,751,250	2,278,750
Outstanding Options @ Year-End	**1,711,111**	813,750	795,000	742,500	147,500
Fully Diluted Shares @ Year-End	**21,206,954**	10,825,000	9,556,250	9,493,750	2,426,250
Year End Market Capitalization	**77,983,372**	18,020,250	17,522,500	21,003,000	3,099,100
Average Daily Production					
Natural Gas (mmcf/d)	**8.13**	2.38	1.61	1.79	2.00
Natural Gas Liquids (bbl/d)	**22**	8	1	2	3
Oil (bbl/d)	57	**63**	63	69	58
Gas Equivalents (mmcfe/d @ 6:1)	**8.60**	2.80	2.00	2.21	2.36
Oil Equivalents (boe/d @ 6:1)	**1,434**	467	333	369	394
Per Unit Statistics ($/mcfe @ 6:1)					
Average Price	**4.02**	4.71	5.05	2.69	2.02
Royalty Costs, net of ARTC	**(0.71)**	(0.72)	(0.79)	(0.46)	(0.14)
Production Expenses	**(1.00)**	(0.89)	(1.12)	(0.65)	(0.60)
Operating Netback	**2.31**	3.10	3.14	1.58	1.28
General & Administrative	**(0.52)**	(0.83)	(1.19)	(0.78)	(0.25)
Capital and Other Taxes	**(0.04)**	(0.06)	(0.02)	(0.02)	0
Other Income / (Expenses)	**(0.03)**	0.26	0.75	0.15	(0.07)
Cash Flow From Operations	**1.72**	2.47	2.68	0.93	0.96

	2002	2001	2000	1999	1998
Proven Producing Reserves @ Year-End (Gross Company)					
Natural Gas (bcf)	**13.7**	7.06	5.08	4.70	5.14
Natural Gas Liquids (mstb)	**60**	34	17	0	5
Oil (mstb)	**205**	119	142	171	215
Gas Equivalents (bcfe)	**15.32**	7.98	6.03	5.37	6.46
Oil Equivalents (mboe)	**2,554**	1,330	1,005	955	1,076
Total Proven Reserves @ Year-End (Gross Company)					
Natural Gas (bcf)	**21.00**	11.17	6.36	4.70	6.34
Natural Gas Liquids (mstb)	**72**	49	24	0	5
Oil (mstb)	**237**	152	175	203	368
Gas Equivalents (bcfe)	**22.80**	12.38	7.55	5.92	8.58
Oil Equivalents (mboe)	**3,800**	2,063	1,259	987	1,430
Probable Reserves @ Year-End (Gross Company)					
Natural Gas (bcf)	**8.70**	3.84	2.49	0.89	2.12
Natural Gas Liquids (mstb)	**29**	24	11	0	9
Oil (mstb)	**162**	71	84	76	28
Gas Equivalents (bcfe)	**9.79**	4.41	3.07	1.34	2.35
Oil Equivalents (mboe)	**1,632**	735	511	224	391
Established Reserves @ Year-End (Gross Company)					
Natural Gas (bcf)	**25.30**	13.09	7.61	5.15	7.40
Natural Gas Liquids (mstb)	**87**	61	30	0	9
Oil (mstb)	**318**	188	216	241	383
Gas Equivalents (bcfe)	**27.70**	15.58	10.07	7.56	11.32
Oil Equivalents (mboe)	**4,616**	2,431	1,513	1,099	1,625
Established Reserves Life Index (@ Year-End)					
	8.8	14.3	12.5	8.2	11.3
Land Position @ Year-End (000's)					
Gross/Net Acres	**441/223**	250/90	211/74	130/44	142/41
Average Working Interest	**51%**	36%	35%	34%	29%
Undeveloped Gross/Net Acres	**276/146**	166/62	133/51	109/35	N/A
Gross Option Acreage	**45.6**	19.2	21.7	20.2	0.0
Wells Drilled					
Gross	**75**	65	6	17	2
Net	**54.6**	19.7	2.8	3.1	0.2
Average Working Interest	**73%**	30%	46%	18%	10%
Full Time Employees @ Year-End	**12**	5	5	4	0

* All volume conversions are at 6 mcf per boe.

Abbreviations and Terms

Abbreviations

ARTC	Alberta Royalty Tax Credit
bbl	barrels (of oil or natural gas liquids)
bcf	billions of cubic feet (of natural gas)
bcfe	bcf equivalent
boe	barrel of oil equivalent (6 mcf = 1 boe)
GJ	Gigajoule
mboe	thousands of barrels equivalent
mcf	thousands of cubic feet (of natural gas)
mcfe	mcf equivalent (1 barrel of oil/natural gas liquids = 6 mcfe)
mmcf	millions of cubic feet (of natural gas)
mmcfe	mmcf equivalent
mstb	thousands of barrels (of oil or natural gas liquids)
NGL's	natural gas liquids (propane, butane and condensate)
/d	per day

Glossary of Terms

Established Reserves	Proved reserves plus 50% of probable reserves.
Recycle Ratio	Operating netback divided by reserve replacement costs. This is a measure of a Corporation's ability to create value through reserve additions.
Finding and Development Cost	Capital expenditures including acquisitions, divided by Established Reserve additions. This is a measure of how efficiently a Corporation has employed capital to add reserves.
Reserve Replacement Ratio	Established Reserve additions divided by annual production volumes. This is a measure of how effective a Corporation was in replacing annual production volumes.
Reserve Life Index	Year-end Established Reserves divided by annual production volumes. This is a measure of the life span of a Corporation's reserve base if current production levels were held constant.

Metric Conversion Factors

IMPERIAL	METRIC
1 acre	0.405 hectares (ha)
1 bbl	0.159 cubic metres (m3)
1 foot	0.3048 metres
1 mcf	0.02817 thousand cubic metres (103m3)
1 mcf	1.0549 gigajoules (GJ)
1 mile	1.609 kilometres (km)

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Toby R. Neugebauer (1, 3)
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(1) Member of the Audit Committee
(2) Member of the Reserves Committee
(3) Member of the Compensation Committee

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Bruce D. Gigg - VP Engineering
Kelly D. Kerr - VP Finance & CFO
Bruce G. McIntyre - President & CEO
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Richard K. Rathier - VP Exploration
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